Presented to the:

New Jersey Board of Public Utilities

Final Report

Focused Audit of the Planning, Operations and Maintenance Practices, Policies and Procedures of Jersey Central Power & Light Company

Docket No. EX02120950

June 22, 2004

(Volume I)

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Introduction

The audit process is necessarily an iterative one in which the auditors' understanding of the audited company, and the audited company's understanding of the nature and kind of information required by the auditors to convey an appropriate understanding of its business, personnel and functions, evolves. Indeed these exchanges and discussions were the basis for JCP&L and the Staff of the NJBPU to arrive at a Memorandum of Understanding ("MOU") that was ultimately approved by the NJBPU on March 25, 2004 with respect to our "Priority One" recommendations as set forth in an Executive Summary for Immediate Recommendations before Summer 2004 dated January 9, 2004. More specifically, the MOU addresses actions that may be of value to improve the reliability of electric delivery for the Summer 2004 peak period. The MOU adopts, as recommended or in principle, all of our "Priority One" action items except the following two recommendations:

1. The FirstEnergy wood pole testing program for distribution poles adopted for JCP&L should be changed to, at a minimum, a 15-year cycle. The FE program has no periodicity.

2. FirstEnergy does not include retirement of aging transformers in a life cycle program. Instead, transformers would always be operated to failure. Our recommendation is the requirement to replace older transformers utilizing a proper life cycle program over the next 10 years, based on full testing and assessment, to avoid possible adverse impacts on reliability.

Subsequent discussions and additional information provided by the Company in conjunction with our later draft have also led to the resolution or refinement, as reflected herein, of our concerns with respect to many of our "Priority Two" and "Priority Three" recommendations. We have attempted to reflect that iterative process within this report. The MOU has resolved our concerns as reflected in a particular recommendation, whether or not the recommendation was adopted in whole, in part, or at all.

1. Executive Summary

General

On September 24, 2003, the New Jersey Board of Public Utilities (NJBPU, or “Board”) retained Booth & Associates, inc. (“Booth”) to perform a Focused Audit of the Planning, Operations and Maintenance Practices, Policies and Procedures of Jersey Central Power & Light Company (JCP&L) and recommend action plans to be implemented by JCP&L in order to improve its service reliability. This document is the Final Report regarding the findings of the investigations conducted by our organization.

On August 2, 2002, severe thunderstorms resulted in approximately 180,000 electric customer outages in Jersey Central Power & Light’s (“JCP&L”) Central New Jersey Region. Approximately 40,000 customers were without electricity for over three days, and the total restoration was not completed until five days after the storm. The New Jersey Board of Public Utilities initiated an investigation into the storm-related outages, establishing Docket No. EX02120950. On February 18, 2003, the Board and JCP&L signed a Stipulation and Agreement of Settlement in Docket No. EX02120950. This focused audit addresses Item 8 of the Stipulation, which provides for the Board Staff to conduct a review and focused audit of the Company’s Planning and Operations and Maintenance Programs and Practices, its compliance with the previous focused audit and Board Regulations and applicable Statutes.

Audit Description

The primary scope of this audit is to:

1. Investigate JCP&L’s electric infrastructure and its capability to meet both peak and energy demands including growth.

2. Investigate the extent to which necessary facility upgrades and improvements have been made. Review the company’s planning ability and the company’s ability to focus on growth and reliability and make recommendations for improvements. Review capital investments related to reliability.

3. Review current and planned reliability improvement programs and recommend an action plan to increase reliability, reduce customer outages and improve customer satisfaction.

4. Provide recommendations in all areas deemed to require improvement pertaining to reliability and restoration of service.

5. Establish objective performance standards.

6. Investigate JCP&L's ability to restore service in an expeditious manner, using all appropriate resources.

In order to accomplish these tasks, a comprehensive assessment of JCP&L's electric transmission and distribution systems was performed that included:

1. A condition assessment of the electric infrastructure based on inspection of a sample of transmission, subtransmission, substation, underground and overhead distribution facilities.

2. Review of Capital Improvements for the past five years and five years into the future.

3. Review of the budget priorities between Transmission and Distribution.

4. Review of the load and energy forecasting process and determination if adequate resources have been allocated to accommodate load growth.

5. Review of organization and staff.

6. Review of maintenance systems, policies and practices.

7. Review of system reliability and contingency planning.

8. Evaluation of current procedures and systems utilized for restoration of service.

9. Review, analyze and report compliance with applicable FE/GPC Merger stipulations.

10. A total of 29 interviews with 41individuals were completed. These included key staff and management level personnel at JCP&L, NJBPU Division Directors, labor union representatives, and Town Mayors and Managers.

11. Field work for the audit was completed on December 3, 2003.

Incorporated in the assessment are three primary elements of evaluation for determination of reliability deficiencies and establishment of the action items necessary to elevate the JCP&L reliability to at least an average level:

(1) Detailed interviews with management level personnel in the various operating units including senior management.

(2) A field observation and condition assessment of the electric system infrastructure.

(3) A review of all critical operations and maintenance processes.

Firm Experience

Booth & Associates, Inc. has been providing professional engineering services since 1960. Our electric utility national experience comprises over 300 clients in 38 states including 15 state and national organizations, with over 200 electric utility clients. The Company currently has active projects for 110 of our electric utility clients.

The Team assembled to conduct this Focused Audit has a varied and extensive background. Members included:

Team Member	Years of Electric Utility Experience
Gregory L. Booth	40
Donald A. Wright	36
R. L. Willoughby	35
Edward C. Mullinax	35
Steve D. Hodgin	33
Steven J. Bowling	33
John H. Widdifield	32
Dwight E. Davis	32
Harry G. Buckner	32
Robert L. Misenheimer	31
Harold L. Cook	29
J. Onnie Christian	28
Mark E. Cullifer	26
Tommy Newton	26
Alan W. Stoddard	24
Ralph N. Seamon	21
Brad Buckner	19
Steven A. Miller	10
Mike Massey	9
Mary D. Stancil	7
David K. Taylor	6
Misty R. Robinson	6
Shawn C. Eaton	5
J. B. Williams	3
Cumulative Experience	558
Average Experience	23

Major Findings

It is extremely important for the Board and the public to recognize that the compilation of problems and deficiencies identified throughout this Focused Audit of Planning, Operations and Maintenance Practices, Policies and Procedures of Jersey Central Power & Light Company are predominantly in the areas which have developed over a course of ten to twenty years. FirstEnergy, through its purchase of GPU and the Jersey Central Power & Light Company, have inherited virtually all of the deficiencies identified. It is our opinion that FirstEnergy did not, through its own actions, create the preponderance of deficiencies and dilemmas which must be corrected. It is, however, recognized that FirstEnergy took ownership of the system, and as such, is the party responsible for operating and maintaining an electric utility system following nationally published standards and good and prudent utility practice in a manner consistent with what is deemed appropriate by the NJBPU and the public. Hopefully, a cooperative process of staged implementation of prudent programs consistent with reliability enhancement goals in the most reasonably practical and economical manner will lead to an operating utility of which the Board, the public and FirstEnergy can be proud. Booth, the Board, including its staff, and FirstEnergy have strived throughout the Focused Audit process to maintain the highest level of professionalism and cooperation.

There are many areas of positive progress and improvement on the part of FirstEnergy as it relates to Planning, Operations and Maintenance Practices, Policies and Procedures of Jersey Central Power & Light Company. These improvements and processes implemented by FirstEnergy, including but not limited to, the Accelerated Reliability Improvement Plan (“ARIP”), will in some instances take years in order to demonstrate effectiveness in improving service reliability.

This report is a compilation of Booth & Associates, Inc.’s opinions based on our extensive experience in the electric utility industry and our interpretation of the data provided by JCP&L and FirstEnergy combined with our field assessments. The report recommendations and action plan and position stated herein are those of Booth & Associates, Inc. and are predicated on our experience of over 40 years of providing consulting engineering and design services to electric utilities in 38 states. The reader should understand that others may have differing opinions or beliefs and may identify other methods in which to interpret data in order to improve service reliability. Notwithstanding this, Booth believes that its report, recommendations and action plan, if adopted, will result in the desired improvement in system reliability for the using and consuming public.

The following summarizes the major (although not all of the) negative findings that we made with respect to the JCP&L system:

1. The majority of JCP&L's substations are old; 266 of the 483 transformers are more than 30 years old. Inspection and testing of substation equipment appear to be in line with FirstEnergy's Substation Preferred Practices and Methods. Fifty-eight (58) transformers presently in service have experienced all-time peaks that exceed the transformer nameplate ratings.

2. JCP&L's practices for grounding substation fences do not meet NESC Code. Moreover, while JCP&L does consistently place marking signs on substation fences, steel structures, and equipment inside the substations, most of the signs do not conform to the latest standards. JCP&L has agreed, among other substation grounding commitments it has made, to seek IEEE interpretative guidance about its fence grounding practices and to abide by that guidance. JCP&L has also agreed to replace faded or cracked signs with signage that will comply with the applicable latest standards. See MOU paragraphs 2, 9, 10, 11, and 12.

3. The JCP&L system contains approximately 2.1 circuit feeders per transformer. The larger substation transformers combined with our concerns about JCP&L's substation transformer overloading practices creates a concern that individual circuits are loaded too high.

4. For the substations inspected, direct lightning strike shielding was non-existent for the most part. Only three (3) of the 24 substations inspected had any kind of lightning protection. JCP&L has acknowledged that such protection was not standard JCP&L practice in the past, but states that it is part of current construction standards for new installations.

5. JCP&L uses an approach towards repair and maintenance of distribution poles which is often temporary in scope rather than completing a permanent repair upon identification of a repair or maintenance need. Rotten poles are either patched instead of replaced or simply left in place with no action. Damaged poles are splinted as a means of lowering maintenance cost. Only double red-tagged poles are replaced. Double red tag poles mean that they cannot be climbed. This means the pole inspector may have called for this pole to be replaced not once but twice or the inspector has determined that the pole is unsafe to climb. To further exacerbate the distribution pole maintenance deficiency, JCP&L has eliminated the cyclic pole inspection program. Therefore, by default, JCP&L has gone to a program of replacement upon failure for low growth areas of its system. Other problems observed included:

   (a) Frequent use of extensions instead of replacement of a pole with the proper size.

   (b) Booth & Associates could not identify make-ready engineering used for attaching telecommunication cables to joint-use poles.

6. Based on our observations, we believe that JCP&L's padmount distribution transformers are in need of immediate attention because we estimate that perhaps 40% of JCP&L's padmounts have no pentahead bolts, which conflicts with the requirements of the NESC. Also, we observed that fiber boards on live front transformers have been removed, which also conflicts with the NESC.

7. JCP&L's capital expenditures for the last five years have averaged $160 million. The 2003 Budget is $102 million and $120 million for the years 2004-2007. Operating and maintenance expenditures have averaged $117 million for the last five years. The 2003 Budgeted T&D O&M is $161 million, including an incremental $21 million for the Company's voluntary Accelerated Reliability Improvement Program. These levels of spending have not been sufficient to prevent the deterioration of the electric infrastructure.

8. Insufficient Distribution transformer capacity and improper system configuration (lack of sectionalizing) will cause problems at the distribution level until corrected.

   JCP&L has addressed some of these concerns in MOU paragraph 4 in which it has agreed to continue and complete its ARIP, which, among other things, includes the fusing of certain circuit lateral taps, where necessary and possible, as well as certain main feeder sectionalizing, consistent with JCP&L's circuit protection philosophy.

9. JCP&L's current organizational structure is a continued refinement of a regional approach adopted by GPU Energy prior to the FE/GPU merger. Mr. Stephen Morgan was recently elected President of JCP&L effective January 5, 2004. Reporting to the new President of JCP&L will be the two current Regional Presidents.

10. The current union/management relationship at JCP&L is strained and impairs the Company's ability to properly maintain and improve its system. The use of sick time, the callout response of the unionized employees and the use of overtime continue to present problems for JCP&L's management.

    JCP&L has acknowledged the strain in its relationship with the union and has highlighted its view about the necessity to change practices relating to such things as absenteeism, callout response and overtime controls, in order to make the Company function smoothly and effectively.

11. During 2002, FirstEnergy transitioned from GPU engineering, design, construction and maintenance practices to standardized FirstEnergy policies that are applicable to all FE operating utilities. The design philosophy of the FirstEnergy Corporation is built around the excess utilization of thermal

capacity in equipment and overhead conductors. The system is built to meet actual, not projected, load requirements. JCP&L planning procedures and policies result in a program that has all the characteristics of operating equipment to its ultimate failure. Given the current condition of the JCP&L system, this philosophy results in significant risks that equipment will fail during peak periods when it is stressed and customers will incur extended outages until replacement equipment can be installed. Fourteen percent (14%) of the transformers in Central Region and seventeen percent (17%) in the Northern Region have experienced all-time peaks in excess of their nameplate rating. Considering the historical growth rate in peak demand, it is very likely these percentages of overloaded equipment and expected failure rates will escalate well beyond the already unacceptable levels.

12. JCP&L's combined Northern and Central CAIDI for the year 2002 was the second highest level (2.53 hours) in the last ten years. JCP&L's combined Northern and Central Areas SAIFI for the year 2002 was also the second highest level (1.18) in the last ten years. In the Northern Region the highest cause of interruptions and customer minutes for 2002 was tree-related outages. In the Central Region the highest cause of interruptions and customer minutes for 2002 was equipment failures.

13. JCP&L's inability to restore service in an effective manner following the August 2002 heat-related events was caused primarily by inadequate callout procedures and poor employee response, as well as, lack of mutual aid crews from other utilities and contractors. FirstEnergy's corporate-wide Emergency Storm Restoration Plan has functioned well through two major emergencies, the July 2004 Barrier Peninsula outages and Hurricane Isabel. Until management/union difficulties are improved, the callout response may continue to be a difficult problem to control. Mutual aid from mid-Atlantic utilities will not be a reliable source of aid during wide-spread emergencies that sometimes occur on the East Coast. Continued commitment by FirstEnergy with Ohio-based crews should insure that the current ability to respond is maintained.

14. During the interview of the two Regional Presidents on November 20, 2003 and throughout much of the other interview process, there were two substantial overriding themes being purported to at all levels of management. These themes were (1) safety is the company's number one priority and (2) FirstEnergy intends to impose on the Jersey Central Power & Light Company Planning, Operations and Maintenance Practices, Policies and Procedures the FirstEnergy's "Best Practices" developed processes. Although these were overall themes of management including the two Regional Presidents, we often determined neither theme seems to be reflected in the actual system operations and maintenance procedures or planning processes as reflected in the field or through the staff's practices. Although it is believed that this is the

intention of the FirstEnergy management and the Jersey Central Power & Light Company management, Booth is confident that it will take a significant cultural shift from both the FirstEnergy Board and management level and the Jersey Central Power & Light Company mid-level management and worker level for the stated desires of management to become an operating reality.

Only through mild weather resulting in lower system peak demand and the luck of nature cooperating with a less severe summer from the standpoint of storms, lightning, and winter from the standpoint of severe winter storms, do we anticipate 2004 to show any marked improvement in system reliability based on the programs currently being implemented. Booth has established that Jersey Central Power & Light Company senior management, including their direct interface with mid-level management at FirstEnergy, are committed to the improvement in service reliability including Operating Practices, Policies and Procedures. Booth has been unable to establish that mid-level and lower level management and operating personnel have the same goals and commitment as upper management. Furthermore, Booth has determined that JCP&L has sufficient construction, operation, and maintenance personnel to operate the system and implement the necessary programs from a line construction/operations and maintenance standpoint. Booth has also established that JCP&L does not have sufficient mid-level management and engineering staff with the education, training, and authority to assure the implementation of upper management's goals and commitments. Furthermore, there is an insufficient level of management oversight, planning, inspection, and assurance of implementation.

JCP&L is now in a management transition with the appointment of Mr. Morgan as President. It appears Mr. Morgan is actively evaluating all the findings identified in the Focused Audit process.

15. For Subtransmission Planning, JCP&L beginning in 2002 has implemented the following changes:

    (a) The 50/50 forecast is used for single contingency line outage analysis. The 90/10 forecast previously used is included for informational purposes only.

    (b) Beginning in the year 2001, the subtransmission conductor emergency ratings are based on a reduced ambient temperature of 30° C compared to a previously used standard of 35° C.

    These changes in JCP&L planning criteria represent a focus that does not provide a prudent balance between economics and reality. JCP&L focuses nearly exclusively on cost savings. The JCP&L criteria does not provide reserves to accommodate the high peaks that occur at high ambient temperatures, often with no wind, thus reducing the real system capability. The JCP&L process maximizes the economic use of the system; however, it inherently will drive reliability down due to the inability to meet the extremes.

16. JCP&L's current high circuit loadings require that auto-load transfer schemes must be disabled during the summer peak periods at 80 substations in order to avoid overloading of system components during first contingency conditions.

    JCP&L acknowledges that it does disable its auto-load transfer schemes during the summer, but claims that this is limited to the distribution system as opposed to the subtransmission system.

The following summarizes the major (although not all of the) positive findings that we made with respect to the JCP&L system:

1. JCP&L's high voltage transmission facilities (500 kV, 230 kV, and 115 kV) are in satisfactory condition; however, regular inspection of the 115 kV facilities is due and should be performed as scheduled, which JCP&L has indicated will occur.

2. The 34.5 kV subtransmission facilities overall are in adequate condition. The network is not properly protected from lightning. Approximately 8% of the poles need to be replaced, and other equipment is in need of immediate maintenance and repair.

3. Booth's evaluation using the FERC Form 1 filed by JCP&L for total system load, (fully diversified, not non-diversified) results in a total system growth of 4.04% adjusted for cooling degree days and using a four-year regression analysis. This supports the region percentages as stated by Booth from BA-2-8. JCP&L's load forecasting methodologies have developed over time and are utilized for local and regional planning. JCP&L, with its retained capacity of approximately 1,200 MW and the strong markets which exist in PJM provide adequate generation resources to accommodate JCP&L's projected growth. Purchasers of JCP&L's Basic Generation Service in the New Jersey auctions must meet all PJM requirements as a Load Serving Entity. The projected generation reserves based on resources commitment to meet load for the 2004 summer period is 18.9%. Therefore, there are good assurances that adequate generation is available for future load in New Jersey. Generation and Bulk Power transmission-related reliability should not be a problem over the near-term planning period. Insufficient substation transformer capacity and improper system configuration (lack of sectionalizing) will result in reliability degradation at the Distribution level until trends are corrected.

   The growth rate is robust and will result in substantial capacity strain on the system if a more aggressive capital improvement plan is not implemented.

JCP&L, after numerous requests by Booth, has been unable to refute the FERC Form 1 data and growth rate. JCP&L additional data and discussions continue to exacerbate the incongruence in their various rebuttals. JCP&L provided further data that indicate that the Northern Region has experienced a four-year negative growth. Yet, JCP&L states it does not require a formal distribution pole inspection and replacement program because the system growth is so rapid that they will be handling all of the poles due to additions and replacements created by the system growth. If a 15-year cycle is the proxy for the JCP&L statement, this would indicate a system growth of approximately 6.7%. Due to the continued incongruence of data from JCP&L, we continue to use the filed data with FERC as our basis for the growth rate.

4. JCP&L's workforce since the FE/GPU merger has been relatively stable due to the Board's requirement that through October 2004, JCP&L's bargaining unit employees are protected against involuntary layoffs and that no Voluntary Enhanced Retirement Program or any other layoff can be implemented without first petitioning the Board for approval. Total JCP&L staffing in 2002 was 1,610 management and bargaining unit employees. The number of employees YTD through August 2003 was 1,584. The reduction in workforce has been by retirement and voluntary separation. The Regional Presidents felt that JCP&L may be overstaffed at the line level. As normal policy, JCP&L uses contractors to perform vegetation management, as well as, specialized construction. They have also used contractors to implement the majority of their Accelerated Reliability Improvement Program. JCP&L's current line workforce appears to be adequate to conduct the required inspections, maintenance and testing of facilities and JCP&L has significant flexibility through the use of contractors to accommodate increased levels of work. At this point in time, there appears to be no gap between reliability requirements versus resource adequacy. Should JCP&L adopt a life cycle transformer management program, additional maintenance mechanics or contract maintenance crews may be needed to insure that regularly scheduled maintenance proceeds at the same time other critical remediation work is performed.

5. Since the FE/GPU merger, FirstEnergy has embarked upon a significant technology change. SAP has been adopted system-wide as the Company IT platform and a new work management module (CREWS) installed. PowerOn, the primary tool for outage management, has been modified and continues to be modified. These changes are positive and provide current processes and systems for execution of the Company's capital and maintenance plans. Refinements in the systems and software will be required and FirstEnergy has follow-up employee training scheduled to improve utilization of SAP and CREWS by its employees.

Paragraphs 1, 5, and 19 of the MOU concerning the GIS audit, the 34.5 kV telemetry project to establish clear alarm points for the RDO, and EMS monitoring capability or real-time metering at selected substations address this finding.

6. JCP&L is in general compliance with applicable FE/GPU merger Stipulations.

The Board of Public Utilities (BPU) will need to determine how to best balance the rate recovery and revenue stream for Jersey Central Power & Light Company (JCP&L) that would allow FirstEnergy not to be seriously damaged economically as it attempts to reach acceptable levels of reliability through the expenditure of capital resources and increased operation and maintenance expenses. Booth & Associates, Inc. does not believe that JCP&L can significantly improve its reliability through the implementation of advanced software and policies. Real infrastructure changes are required and real process changes must be enforced. As an example, JCP&L, in its response to the executive summary initially produced on January 9, 2004, indicated that it had made a significant improvement in system protective coordination and had installed 1,103 new fuses and 139 reclosers. Although this sounds like a large number, on a utility the size of JCP&L with 1,012 circuits, this is only one new fuse per circuit and is slightly over one additional recloser per 10 circuits. Although this is a first step, it is very short of the level of change that is truly required.

We believe FE has good intentions; however, they are falling far short of putting forth the effort and capital into making any meaningful impact on reliability. JCP&L is in the last quartile of service reliability comparisons in the electric utility industry, utilizing the standard in customary electric utility industry methods of measurement. FE and the BPU need to have a plan to reach at least industry average service reliability standards in the near term (3 to 5 years). It cannot be expected that JCP&L will make an immediate turnaround. JCP&L will need to implement certain improvements to make real and meaningful improvements in service reliability over the next three to five years. Furthermore, JCP&L will need to sustain the programs and processes that are an ultimate outgrowth of this Focused Audit if they are to maintain at least an average service reliability level.

The FE (JCP&L) Accelerated Reliability Improvement Plan proposals are, in fact, ordinary, customary utility practices and should have been in place as a part of the normal daily and annual practices of JCP&L. These programs are not over and above what should be expected on an on-going basis. However, it is acknowledged that the programs and projects within the ARIP are accelerated in terms of scheduling, scope and/or scale. The observations contained in this focused audit and the recommendations and action items have been developed in an effort to be as fair and open and even-handed as possible. Booth & Associates, Inc. has utilized its experience in the electric utility industry since 1960, spanning over 300 clients in 38 states to provide what we believe is a very fair and even-handed focused audit report and assessment. We would not recommend that the BPU or its staff attempt to micromanage FE or JCP&L. For that reason, we have outlined what we believe are appropriate measurement tools to assess progress. Our recommendation and action items are prioritized in such a manner that will allow JCP&L and FE the opportunity to select and prioritize, within their own implementation process, these recommendations in a manner which they believe will most appropriately allow them to meet the reliability standards recommended in this focused audit. We would recommend that the BPU give JCP&L the opportunity, time, and rate relief to implement the recommended action items as they deem most appropriate to achieve the reliability goals and standards outlined herein. We would only recommend that BPU delve into mandatory implementation of specific recommendations and action items upon JCP&L's failure to meet a prudent timeline for achievement of the reliability goals contained herein.

Summary of Recommendations

1. Performance standards to be met by JCP&L should consist of two parts –

System Overall Standards. System reliability indexes excluding major events should not exceed the following:

CAIDI – 1.3 hours
SAIDI – 1.5 hours
SAIFI – 1.0 interruptions

System Component Performance Standards must meet the following standards:

A. Substation Capacity

1. When actual load reaches 95% of nameplate transformer capacity, JCP&L shall develop and budget a remediation plan composed of one of the following actions:

   (a) Replace transformer
   (b) Add transformer capacity in substation
   (c) Shift load so that the transformer is less than 80% loaded based on nameplate rating
   (d) Shift load to a new transformer.

2. When actual load reaches 110% of the nameplate rating, implement the remediation plan within 90 days.

B. Feeder Circuits

All of JCP&L's circuits will be classified into one of the following types of feeders that must meet the following criteria:

1. Industrial

   (a) Defined as any circuit that serves at least one customer with a peak load of ≥ 1,000 kW or uses more than 5,250,000 kWh per year.
   (b) Action is required when the circuit CRI exceeds 80 or momentary outage for any industrial customer exceeds five per year.

2. Commercial

   (a) Defined as any circuit that serves ten or more customers using over 680,000 kWh per year.
   (b) Action is required when the circuit CRI exceeds 100 or momentary outages exceed 20 per year per feeder or the SAIDI is ≥ 1.5 hours per feeder.

3. Urban – Residential

   (a) Defined as a circuit operating at 300 amps or more normal peak or customer average use greater than 1,200 kWh per month.

   (b) Action is required when the circuit CRI exceeds 100 or momentary outages exceed 30 per year per feeder or SAIDI ≥ 3.0 hours per feeder.

4. Rural – Residential

   (a) Defined as a circuit operating at less than 300 amps per phase per feeder annual peak or average customer use less than 1,200 kWh per month.

   (b) Action is required when the circuit CRI exceeds 130 or momentary outages exceed 40 per year per feeder or SAIDI is ≥ 5.0 hours per customer or feeder per year.

C. UG Faults

1. Any section of underground cable experiencing more than two faults due to cable degradation in two years excluding dig-ins or other external damage shall be replaced.

2. Any underground cable with exposed concentric neutral exceeding 15 years age shall be tested every three years to assess the condition of the concentric neutral. If the original installed standards are not met, the cable sections shall be replaced.

D. OH Conductor Standards

Overhead conductors shall not be operated in excess of the following standards:

1. Distribution voltages – current loading using 167° F normal design, 2 fps wind velocity, 35° C ambient and sun. For load transfer, 200° F emergency.
2. 34.5 kV local transmission – all network operating conditions must contain single contingency planning. Current loading at 212° F normal design, 2fps wind velocity, 35° C ambient and sun.

E. Min/Max Voltage

The minimum and maximum service voltages shall meet the Electrical Power Systems and Equipment Voltage Rating (60 Hz) specified in ANSI C84.1-1995.

F. Power Factor

JCP&L shall maintain lagging power factor at 99% in June-September and December-March, and 96.5% at other times at all distribution substations measured at the high side terminals of each transformer. Leading Power Factor during non-peak periods should not exceed 98%.

G. Power Quality

JCP&L shall meet all requirements for IEEE-recommended practices and requirements for harmonic control in electrical power systems, IEEE Standard 519-1992 Section 10 – Recommendations for Individual Customers and Section 11 – Recommendations Practices for Utilities.

H. Facilities Connections Requirements (FCR):

JCP&L shall meet or exceed the FCR published by PJM.

2. JCP&L should not divert its attention from first completing all of the items identified in its Accelerated Reliability Improvement Program. We have identified within this accelerated reliability initiative several areas which

require expansion in order for the program to have the opportunity for maximum reliability enhancement achievement. The areas which should be expanded prior to the Summer 2004 Peak are:

A. The expansion of system-wide sectionalizing equipment should include the installation of fuses or reclosers on all taps exceeding five spans.

   Paragraph 4 of the MOU, which provides, among other things, for JCP&L's continued fusing of certain circuit lateral taps and certain main feeder sectionalizing consistent with JCP&L's circuit protection philosophy, addresses this recommendation.

B. The protective coordination enhancements should be implemented with a variety of coordination schemes, recognizing the necessity to have different protective coordination methods for industrial circuits, commercial circuits and residential circuits.

   Paragraph 4 of the MOU, which provides, among other things, for JCP&L's continued fusing of certain circuit lateral taps and certain main feeder sectionalizing consistent with JCP&L's circuit protection philosophy, addresses this recommendation.

C. The GIS Audit process should eliminate the significant time lag in the AM/FM system being available to the RDO and PowerOn. Also, the present duplication of effort and associated time lag of data entry into PowerOn should be eliminated. During the November 5, 2003 interview and demonstration of PowerOn, JCP&L stated that PowerOn circuits are manually built and that the Vision AM/FM GIS information is manually input into the SmallWorld GIS Database residing in PowerOn. It was further stated by Mr. Homsher that he never wanted the transfer to be automated, even though the next version of PowerOn would allow automatic GIS database update.

   Paragraph 1 of the MOU, which provides that JCP&L will conduct a GIS field audit and provide status reports with respect thereto, addresses this recommendation.

D. As part of the Telemetry Enhancements, JCP&L should establish load level points for both the operations personnel at the RDOs and for the planning personnel. There should be clearly established alarms and a set of operating procedures in place at the RDO for reaction to any alarm condition.

Paragraphs 5 and 19 of the MOU, which provide, among other things, for JCP&L's completion of a specific 34.5 kV telemetry project including RDO alarms and for real time monitoring of loads, addresses this recommendation.

E. The Vegetation Management program and public relations strategy should include a "danger tree" management program. Also, the addition of reclosers or fuses in vegetation management challenging areas should be incorporated.

Paragraph 6 of the MOU, which provides for JCP&L's continued accelerated implementation of FirstEnergy Vegetation Management specifications, which include a "danger" or "priority" tree management component, addresses this recommendation.

F. Include as part of the 34.5 kV system lightning arrester or overhead static wire program the necessity to achieve 10 ohms or less on all "made electrodes" (ground rods) at the grounding connection points to include every arrester location.

Paragraph 7 of the MOU, which provides that JCP&L will continue to include, as part of its applicable construction standards, the objective to achieve 10 ohms or less on all "made electrodes" (ground rods) at the grounding connection points to include every arrester location with respect to its 34.5 kV system lightning arrester or overhead static wire program, addresses this recommendation.

G. Include as part of the 34.5 kV Automation program an aggressive published set of maintenance and testing procedures for all components including batteries and controls.

Paragraph 8 of the MOU, which provides, among other things, that JCP&L will review and assess its existing written maintenance and testing procedures for all components of its 34.5 kV system, addresses this recommendation.

H. The PowerOn OMS upgrade should include the elimination of the duplicated "SmallWorld" GIS data input process.

Paragraph 1 of the MOU, which provides that JCP&L will conduct a GIS field audit and provide status reports with respect thereto, addresses this recommendation.

3. It is recommended that JCP&L adopt a life cycle substation transformer management program:

(a) Consisting of an engineering review of all of the transformers on the system,

(b) Performing a condition analysis for each transformer,

(c) Strengthening the maintenance program by benchmarking all oil and diagnostic testing to detect abnormal conditions early, and

(d) Re-establish a company transformer loading policy.

Implementing these recommendations, Jersey Central will be able to extend transformer life and make informed decisions as to when to replace existing transformers before a costly failure. Given the utility's practice of regularly overloading their transformers, and the overall age of the transformers, the utility needs to prepare for losing many of their 30+ year old transformers within the next ten years. Thus, it is imperative that an action plan be established to replace older transformers. Therefore, it is recommended that:

(a) The utility budget and purchase new transformers for replacements each year for ten years.

(b) The utility implements a life cycle transformer management program.

Jersey Central has nine (9) transformers more than 50 years old that need to be replaced immediately and forty-seven (47) that are in the 40 to 50 year age bracket. They should be given immediate attention given their increased possibility of failure due to age.

4. JCP&L should increase the number of circuits on the system by at least 50%. This requires adding additional feeders to substations with transformers larger than 10 MVA. This practice will reduce the number of customers affected by individual circuit problems and reduce overall customer outage time when extensive switching is needed to restore load.

5. It is recommended that JCP&L to the extent necessary pursue hiring a larger staff of maintenance mechanics and/or bring in contract maintenance crews to allow regularly scheduled maintenance to proceed at the same time other critical remediation work is underway. It is critical, given the average age of the substation equipment, to maintain an aggressive maintenance program. It is not possible to accomplish all the required tasks at hand with the manpower in place. In order to maintain good maintenance practices while upgrading and revamping their electric system, expanding staff will be

necessary. Our Engineers identified the following maintenance-related items:

(a) JCP&L is currently in the midst of a fence replacement program to upgrade the fences at their substation facilities. Standard industry practices call for seven-foot (7') fences (including 1' barbed wire) and bonding the fence posts, fence fabric, and barbed wire to the substation ground grid system. As JCP&L replace their fences, we recommend that the fence posts, fence fabric and the barbed wire at the top of the fence be bonded to the substation ground grid conductors. This additional grounding will help protect the public and JCP&L employees from dangerous voltages in the vicinity of the substation fence during an electrical fault.

    Paragraph 2 of the MOU, which provides that JCP&L will request a rule interpretation from the IEEE, addresses this recommendation.

(b) JCP&L should prepare a safety program addressing substation grounding practices, placing emphasis on fencing and transformer grounding. All field and engineering employees, and contract workers should attend this safety class in the year 2004.

    Paragraph 9 of the MOU, which provides that JCP&L will address training related to substation grounding design practices for appropriate employees, addresses this recommendation.

(c) JCP&L should perform follow up inspections of their facilities to ensure correct grounding practices are followed.

    Paragraph 10 of the MOU, which provides that JCP&L will, among other things, continue to include substation grounding as part of its monthly substation inspection process and will continue to ground out-of-service equipment, addresses this recommendation.

(d) At the Upton substation, a notice was posted on the high-side steel structure stating, "Must Wear High Voltage Boots When Switching." When asked what this sign meant, the response was the substation ground grid had been tested and found to have unacceptable touch potentials. This type of testing should be performed at other substations to verify that the existing ground grid is adequate. Based on comments, it would appear this was the first substation where it was determined unacceptable potentials could occur for faults. It is recommended that "old" substations with limited ground grids be tested in accordance with IEEE Std 80 to verify resistance for ground values required for safety and to determine that grounding continuity exists for all equipment grounding connections.

Paragraph 11 of the MOU, which provides that JCP&L will provide a report to the NJBPU Staff about the various methodologies that are available to test the integrity of the ground grid, addresses this recommendation.

(e) We recommend that JCP&L install new replacement signs at all substations in accordance with the latest ANSI Z535 standards in conjunction with updating their material specifications calling for quality, long-life materials. Twenty-year ratings are available that cover fading and cracking of material. These signs should emphasize action, use proper signal words and colors, show emergency information, and be bilingual if appropriate.

Paragraph 12 of the MOU, which provides, among other things, that as JCP&L replaces faded or cracked or otherwise unreadable warning signs on its substation fences and gates, it will do so with signs that comply with the latest ANSI 2535 and OSHA standards and that all new signs will also comply with the latest ANSI 2535 and OSHA standards, addresses this recommendation.

6. Although work was done as a result of the Phase II Board Order to improve lightning protection at JCP&L substations including the recommended installation of one or more 80-foot tall lightning masts at 27 transmission substations, our Engineers have identified additional problems. The following modifications and recommendations need to be completed prior to the 2004 summer peak period.

Since the effects of a direct lightning strike to an unshielded substation can be devastating, it is recommended that some form of direct strike protection be provided in future stations. Direct strike protection normally consists of shielding the substation equipment by using lightning masts, overhead shield wires, or a combination of these devices. The types and arrangements of protective schemes used are based on the size and configuration of the substation equipment.

Accepted industry standards require that all stations have a static or shield wire over at least the high side equipment and preferably over the entire station. A single shield wire provides a 30-degree wedge of protection from direct lightning strikes to each side of the shield wire as measured from the vertical. This angle may be increased to 45 degrees for areas between shield wires when two or more are used. A single steel mast provides a cone of protection for an angle of 30 degrees from the mast. If more than one mast is used, the angle from the mast may be increased to 45 degrees for areas between the masts. Also, the shield wires or mast must be properly grounded.

We recommend a study of substation outages on JCP&L's system be commenced to determine the impact of lightning on substation operations. Information from the study can be used to determine where static protection is needed on the JCP&L system and whether installing static protection in existing stations is warranted.

With respect to the 34.5 kV system, Paragraph 7 of the MOU addresses this recommendation.

7. JCP&L should implement a construction plan to make necessary repairs and replacements to its Subtransmission system and Underground and Overhead Distribution systems as identified during our condition assessment. Our estimated project costs are identified below in Table 1.

Table 1
Cost Estimate for Recommended Maintenance Actions

Action	Cost
1. Maintenance to Subtransmission System	$32,311,626
2. Maintenance to UG Distribution System	11,646,320
3. Maintenance to OH Distribution System	90,531,520
Total	$134,489,466

8. Beginning in 2004, the tree-trimming cycle in the Northern Region should be shortened in areas that are not trimmed 15' on each side of the pole line.

   Paragraph 6 of the MOU, which provides for JCP&L's continued accelerated implementation of FirstEnergy Vegetation Management specifications, which include a "danger" or "priority" tree management component, addresses this recommendation.

9. As part of ten-year and five-year step long-range planning studies proposed, sectionalizing and fusing should be studied in detail, incorporating actions already completed to determine design changes needed to create a properly coordinated Distribution system and Subtransmission system that complies with good utility practice.

10. JCP&L has no effective work order inspection plan for maintaining construction quality control. Jersey Central and hopefully the entire

FirstEnergy Company should implement a construction inspection program in which every month a minimum of 30% of all construction will be inspected by a qualified engineer producing discrepancy reports and assuring that all discrepancies are rectified. Preferably this engineer will be a licensed professional engineer. As a minimum, this engineer should have at least ten years experience in the design and construction of electric utility facilities and be capable to identify all levels of construction deficiencies and discrepancies both from the design and staking standpoint through the construction and as-build drawings standpoint. Additionally, once every three years an additional independent quality control Operation and Maintenance Survey should be performed on all distribution system components from the substations down to the electric meter for a substantially representative no less than 30% of the system. This should be preferably done on an annual rotating basis such that no less than 20% of the substations in a region have been incorporated into an O&M Survey process each year or that at least 50% of the system has been incorporated into an O&M process every three years as an additional level of quality control inspection.

11. The SmallWorld GIS mapping module contained in PowerOn should be modified so that changes that are made in the Company's AM/FM mapping software are automatically transferred to PowerOn. The current manual transfer of data and circuit development which is characterized by JCP&L as quality control should be eliminated. A more appropriate quality control program should be developed to eliminate manual processes that slow down the transfer of important information into all active systems.

    Paragraph 1 of the MOU, which provides that JCP&L will conduct a GIS field audit and provide status reports with respect thereto, addresses this recommendation.

12. Differences in design standards are used within the Central Region for facilities installed in coastal areas which operate in a salt water environment. The following standard distribution practices should also be adopted and implemented:

    - Stainless steel hardware should be installed throughout the area.
    - Construct with shorter spans to reduce conductor blowout during high winds.
    - Stainless steel transformer tanks should be installed.
    - Primary distribution facilities should be insulated to specifications one level higher than planned operating voltage.
    - Inspections of facilities should be more frequent than non-coastal areas.
    - Infrared tests should be completed annually.

13. NJBPU should conduct a governance audit of JCP&L.

14. The FirstEnergy wood pole testing program for distribution poles adopted for JCP&L should be changed to a fifteen-year cycle beginning in 2004. All current red-tagged poles should be replaced by the end of 2004. During the inspections conducted in 2004, all poles red-tagged should be removed and replaced within six months.

15. For joint-use poles, JCP&L should immediately inspect the poles for proper size class and proper guying based on attachment loading. All make-ready design changes that should have been identified prior to attachment of CATV and telephone lines should be identified and proper action taken to support both the electric utility and telecommunication uses.

    Paragraph 15 of the MOU, in which JCP&L makes certain commitments with respect to its assertion and enforcement of joint-use pole rights and obligations, addresses the recommendations in this paragraph of the report.

16. The Regional Presidents stated that JCP&L plans to rely on the Power Systems Institute Training Program to provide the adequate number of future line workers. As an option, JCP&L should adopt a combined program using an apprentice training program and the PSI program.

17. With respect to subtransmission planning studies, we recommend:

    - Returning to using a 90/10 load forecast for system normal analysis.
    - Returning to using 35° C ambient temperature and 2 feet per second wind when rating conductors and other components. Also, JCP&L should return to industry standard of 75°C (167°F) conductor temperature for normal maximum ratings for local subtransmission conductors. For those newer lines designed to operate at 100 C, the 100° C (212° F) rating would be acceptable for <u>temporary</u> emergency situation.
    - JCP&L should reconductor, add circuits and perform other improvements required to allow auto-load transfer schemes to function for first contingency subtransmission outages without overloading system components.
    - JCP&L should prepare a 10-year local subtransmission plan. This plan should include an interim 5-year step. A new 10-year local subtransmission plan should be prepared every 5 years. This way, there is always 5 years of future planning in existence. This plan should contain both a clear set of design criteria and reliability criteria. It should also reflect the regions' Facilities Connection Requirements and

other FCRs as filed at FERC. It should also consider a plan for transferring portions of the distribution substation load from the 34.5 kV system to higher voltage transmission lines for improved capacity and reliability.

18. Auto-load transfer procedures need to be properly established so they do not have to be disabled during the summer peak periods. Our recommendations are:

    - A more reasonable level for circuit loadings normal loadings should be adopted.
    - Breaker phase relay settings should be reduced to match appropriate conductor loading.
    - Contingency Studies for all distribution lines and substations should be performed.
    - The number of circuits for the system should be increased by at least 50%.
    - Ground trip relays must be installed on all transformers and circuit breakers.
    - Three-phase reclosers should be retrofitted with ground trip relaying or sensing.
    - A program of replacing large, single-phase reclosers with three-phase reclosers should be initiated. Single phase reclosers should be limited to 140 ampere maximum phase trip at which point three phase reclosers with ground trip should be applied.

19. Distribution planning studies should be prepared each year. These studies should be based on three or more years of projected growth. The projections should be the 90/10 projections rather than the 50/50 projections. Improvements dictated by the plan should be implemented prior to the summer peak each year rather than in response to the previous summer peak.

    In conjunction with the recommended distribution planning studies, a distribution contingency study should be prepared for the entire distribution system. Although it may not be feasible to provide contingency backup service to all feeders, it should be the goal of JCP&L to provide backup from same substation feeders or from other substation feeders for most circuits. Along with feeder contingency, distribution substation transformers should be loaded such that other transformers in the same substation or in adjacent substations can serve the load if any single transformer fails. This should be achieved without imposing significant transformer loss of life.

20. It is recommended that the new President of JCP&L, Mr. Steve Morgan, initiate an informal management audit specifically designed for the purpose

of evaluating the intermediate management and engineering staff requirements to assure continuity between the operation, maintenance and construction personnel and senior management.

21. In our opinion, the NJBPU should monitor implementation of its order on all recommended action items approved from this Focused Audit. We recommend a second phase to the Audit that would entail the engagement of an appropriate expert, preferably a firm with multiple levels of expertise and personnel, to audit and monitor JCP&L's program.

22. Booth & Associates, Inc. as part of the iterative process of attempting to reach concurrence with JCP&L on all recommendations has made significant progress. To the extent that JCP&L agrees to fully comply with its May 12, 2004 published Asset Management Strategy (AMS) document including the CRI program as supplemented as follows:

Circuit Reliability Index ("CRI")

JCP&L will target to get 80% of its circuits to a CRI level of 130 or less within 4 years. JCP&L will report on all the circuits on an annual basis until such time as the goal has been achieved as follows:

(i) The Annual Average CRI Rate by Region,

(ii) The three year trend on the average circuit CRI rate per Region,

(iii) The number of circuits with a CRI score of 0-60 compared to a running three-year average number of circuits in the same range and if the number is increasing over 25% or a score change of 8 points, whichever is greater, to take targeted action on the ones that increased and in the case of circuits with CRI scores of 60-100 compared to a running three-year average number of circuits in the same range and if the number is increasing over 10% or a score change of 12 points, whichever is greater, to take targeted action on those circuits which increased.

(iv) Re-normalize CRI goal after 4 years using the NJBPU CAIDI, SAIDI, MAIFI standards and restart the 4 year cycle.

Booth agrees such compliance with these standards and the AMS will be in lieu of requiring Booth recommendations of:

Priority Two Action Items

1. Recommended Performance Standards
4. Increase the Number of Circuit Feeders by at Least 50%
5. Implement Additional Lightning Protection
7. Work Order Process and Addition of Engineering, Inspection, and Construction Observation Staff
8. Planning Studies and Standards
9. Correct Loading Problems that Prevent Automatic Load Transfer Procedures from Operating as Designed
11. System-Wide Sectionalizing Enhancement

Priority Three Action Items

2. Establish Separate Design Standards for Central Region
3. Automated Meter Reading/Remote Power Monitoring

A detailed list and discussion of the recommendations and action items is contained in Section 12. The preceding discussion was simply an overview in executive summary fashion and is not intended to be comprehensive. The comprehensive recommendations are contained in Section 12. The other sections of the report and the Appendices encompass our Focused Audit approach, findings and detailed support.

2. Electric Infrastructure Review

Introduction

JCP&L serves approximately one million customers within 3,200 square miles of northern and central New Jersey. A primary element in assessing the reliability of the JCP&L system was the performance of a condition assessment of the electric system infrastructure to determine the equipment condition and its impact on JCP&L's ability to provide reliable service. Our team of engineers and technicians (with an average of 23 years of design, inspection or operation experience) conducted a system-wide inspection of the JCP&L facilities including the high voltage transmission circuits, the 34.5 kV subtransmission network, distribution substation, pad-mount distribution transformers, and the overhead distribution system. Since JCP&L has two separate operating regions, our selection of equipment inspected was equally apportioned between the two regions.

Booth field crews observed and reported the current conditions of poles, wires, transformers, and other related equipment. The following condition ratings were used during our inspections:

Table 2
Condition Ratings

Number	Description	
1	Unsatisfactory	Extreme corrosion, excessive wear or leaking evident. Wood plant rotten, broken or stressed from overload. NESC or ANSI Code violation. Equipment not accessible.
2	Poor	Significant corrosion and wear evident, operating but needs attention. Little maintenance evidenced, no investment seen, presently leaking.
3	Average	Operating as required, some maintenance is evidenced, some new investment, minor leaks, wear, and vibrations found.
4	Good	Good operating history, maintenance and investment in evidence, good appearance, no leaks, no unusual vibrations, etc., found.
5	New	Less than one year in operation.

The field technicians observed a sampling of the system using a percentage, recognizing that it was not practical to survey all the equipment. Our random sample of substations, transmission lines, subtransmission poles, overhead distribution poles and distribution padmount transformers was accepted by the Board to establish JCP&L's observed system condition when our firm was awarded the contract for the Audit. JCP&L participated in the circuit selection process and suggested including "worst-performing" circuits in the sample. Our teams initially inspected 989 pole locations from 5 circuits in each region selected from the Worst Performing circuits from the 2002 Annual Reliability Report, 5 circuits in each region selected at random, 2 additional circuits that contained additional underground facilities, and 2 circuits in each region chosen by JCP&L as the best of their best circuits. Furthermore, our Engineers and Technicians, "rode out" most of the remaining JCP&L system. Observations from these inspections support the findings from our condition assessment. In our opinion, the sample used is representative of JCP&L's plant in general.

Our Director of Management Services performed a review and quality control process by interviewing each inspector and discussing all locations they rated as unsatisfactory or poor. This process resulted in some reclassification of the findings. Based on these discussions, cost estimates were prepared to determine our best estimate of correcting the deficiencies we observed. The cost for the sample was then applied as a percentage to the rest of the system. This gave us a benchmark as to the total cost to bring some of the maintenance issues up to minimally acceptable standards. Costs associated with necessary capacity increase or upgrades to conductors or transformers were not reflected in the equipment maintenance estimates. The other components of the analysis are addressed later in our report.

High Voltage Transmission Facilities

JCP&L has 612 miles of transmission lines carried on steel tower, steel H-frame, steel pole, wood H-frame, and wood poles. Transmission circuit pole miles by voltage are as follows:

Table 3
JCP&L Transmission Circuit Pole Miles by Voltage

	115 kV	230 kV	500 kV	Total
Mile	192.45*	401.14	17.91	611.50
Percent	31%	66%	3%	100%

* Includes 54.91 line miles of 115 kV on structures occupied by other lines.

The average age of these transmission lines is in excess of 30 years. All of the facilities are under the control of the PJM Interconnection for the purpose of providing transmission services under the PJM Open Access Transmission Tariff.

JCP&L, as a signatory to the PJM Transmission Owners Agreement, operates and maintains its Transmission Facilities in accordance with Mid-Atlantic Area Council (MAAC) and North American Electric Reliability Council (NERC) reliability standards. JCP&L has also transferred the responsibility to direct the operations of its facilities to the office of the Interconnection and the PJM Board. Maintenance on its Transmission Facilities is coordinated with the other signatories of the PJM Transmission Owners Agreement and with the owners of generating facilities within the PJM Control Area subject to the direction of the Office of the Interconnection so as to achieve reliability and operating efficiencies.

Schedule 6 of the PJM Operating Agreement governs the means by which PJM coordinates the preparation of a plan for the enhancement and expansion of the required transmission system in order to meet the demands for firm transmission service in the PJM control area. The process is known as the Regional Transmission Expansion Planning Process ("RTEPProcess").

The RTEPProcess is driven by a number of planning perspectives and inputs, including the following:

- Mid-Atlantic Area Council (MAAC) Reliability Assessment
- East Central Area Reliability Council (ECAR) Reliability Assessment
- PJM Transmission Adequacy Assessment
- PJM Annual Report on Operations
- PJM Load Serving Entity (LSE) capacity plans
- Independent Power Producer (IPP) capacity plans
- Transmission Owner transmission plans
- Merchant Transmission developer plans
- Interregional transmission plans
- Firm Transmission Service Requests
- PJM Transmission Expansion Advisory Committee (TEAC) input

The cumulative effect of these drivers is analyzed through the RTEPProcess to develop a single RTEPlan which recommends specific transmission facility enhancements and expansion on a reliable, economic and environmentally acceptable basis.

These analyses are conducted on a continual basis. As the RTO matures, PJM expects that two regional plans (East and West) will be developed and approved each year with one or more addendum issued in the interim to account for retirements to elements of the plan and the withdrawal of generation or merchant transmission projects from consideration.

PJM's most recent RTEPlan recommends transmission enhancements to meet baseline network system needs over a 2003 through 2007 time frame and to meet the needs of some 132 proposed generation projects representing some 27,500 MW in PJM Generator Interconnection Queues A, B, C, D, E, F, G, and H. The recent withdrawal of several generation projects will require a retooling of the RTEPlan that is expected to result in changes to the baseline facilities and the network and direct connection transmission facilities.

A Booth Team member met with PJM planning and operating personnel and discussed the 2002 Baseline RTEP Report for the 2003-2007 period issued on March 19, 2003.

In order to establish a starting point for development of Regional Transmission Expansion Plans and determine cost responsibility for expansion facilities, a "baseline" analysis of system adequacy and security is necessary. The purpose of this analysis is threefold:

- To identify areas where the system, as planned, is not in compliance with the applicable reliability standards (NERC, MAAC, or ECAR reliability standards).

- To bring those areas into compliance, develop and recommend facility expansion plans, including cost estimates and estimated in-service dates.

- To establish what will be included as baseline costs in the allocation of the costs of expansion for those generation projects proposing to connect to the PJM system.

The system as planned is tested for its compliance with NERC, MAAC, and PJM design standards to accommodate the forecast demand, committed resources, and commitments for firm transmission services for a specified time frame. Areas not in compliance with the standards are identified and enhancement plans are developed to achieve compliance.

PJM has conducted a comprehensive load flow analysis of the ability of the PJM system within MAAC to meet the single contingency, second contingency, and multiple facility outage contingency tests required by Sections IIA, B and C of the MAAC Reliability Principles and Standards, hereafter referred to as MAAC Criteria. This system was also analyzed for its ability to meet the power transfer requirements of Section III and VII B of the MAAC Criteria and to determine compliance with the Stability Requirements Section IV of the MAAC Criteria. The PJM system within the ECAR reliability council was planned for 2007 to meet

ECAR Reliability Standards 1 and 2. Double circuit tower outages and bus faults, as specified in ECAR Reliability Standard 3, were also evaluated. Delayed clearing of a single line to ground fault of a generator, bus section, or transmission element (ECAR Reliability Standard 3) is still under evaluation. In addition, a short circuit analysis was conducted to determine fault duties for all 500 kV, 345 kV, and 230 kV breakers on the PJM system. The 2007 system was tested against the same criteria that will be used in the Queue G, H, & I System Impact Studies.

Four areas of the system as planned through 2007 were found to be non-compliant with applicable NERC, or MAAC Reliability Standards. None related to the JCP&L system facilities or service areas. PJM Transmission Owners have elected to install six transmission reinforcements, and these were included in the 2007 base system representation. None of these voluntary reinforcements involved JCP&L facilities or its service area. One project planned by Pennsylvania Power & Light (PP&L) nearing completion could improve reliability on the JCP&L system. Stability Tests required under MAAC Section IV standards showed that the Martins Creek-Morris Park-Gilbert 230 kV line was found to be unstable at light load with maximum generator output at PPL's Martin Creek generating plant. A six (6)-wire upgrade is nearing completion to correct this problem.

We also inspected previous RTEP Baseline/Transmission Owner upgrade plans beginning in 1999. Two JCP&L projects are in service that were scheduled in the 1999 RTEP:

1. Install second East Windsor 500/230 kV transformer

2. Upgrade four 230 kV breakers at Whippany

One project in the 2000 RTEP Baseline plan that may improve reliability on the JCP&L system is the Conectiv project due to be in service by June 1, 2004, to construct a new 230 kV circuit between Cardiff and Oyster Creek. This would increase import capabilities into the Central NJ Region. Another project listed in the Addendum to the 2002 Baseline RTEP Report may also improve reliability in the Central NJ Region. This project is a Conectiv network upgrade scheduled to be in service in June 2006 and involves replacement of both Monroe 230/69 kV transformers.

The PJM Control Area operators have very little impact on Distribution outages or events that may occur on the JCP&L system. Our review of the Control Area Logs for the August 2002 storm and the July 2003 Barrier Peninsula outages showed that PJM took no actions during these emergencies. There were telephone communications and a verbal request for possible voltage support.

Prior to the merger, JCP&L conducted an Aerial Line Visual Inspection Program as its primary maintenance tool for transmission facilities. Under this program, transmission circuits were patrolled annually and an aerial line visual inspection conducted. A five-year cycle was maintained for facilities rated 230 kV and 500 kV, and a ten-year cycle was maintained for 115 kV facilities. Thermographic inspection of all transmission lines was performed on a three-year cycle.

JCP&L maintains that New Jersey complies with the FirstEnergy Transmission Maintenance Manual adopted after the merger. JCP&L provided the following information on its transmission line maintenance program.

- The twice yearly (Spring and Fall) aerial patrols were conducted in 2003.
- Under the Wood Pole Maintenance Program, the ground line inspection cycle is not due in New Jersey until 2008. The climbing inspections will start with the onset of the ground line inspection program.
- Thermovision, per the Transmission Maintenance Manual, is performed as required. Thermovision of the New Jersey transmission system at 115 kV and above was last performed in the year 2000 under the three-year cycle of the GPU program.

JCP&L also maintains that in 2004, the Transmission Maintenance practice is being enhanced by instituting a four-year Comprehensive Aerial patrol of the 69 kV and above transmission facilities within FirstEnergy. JCP&L does not currently have any 69 kV in New Jersey. Accordingly, this enhancement would apply to JCP&L's 115 kV and above transmission facilities.

The following Table 4 shows JCP&L's transmission lines inspected during our Audit.

Table 4
Transmission Infrastructure

High Voltage	Pole Miles	Miles Inspected
500 kV	18	9
230 kV	570	50
115 kV	232	20

Appendix A contains our Engineers' written evaluation of the High Voltage Transmission circuits inspected. Line sections were selected at random to represent a sample of the line types and areas involved.

Transmission right-of-ways system-wide appeared to be in very good condition with minimal vegetation growth. Right of ways had been cleared and sprayed to prevent tree growth. Very few danger trees were evident and right-of-way had good access for maintenance.

Five hundred kV (500 kV) transmission lines are located only in the Central Region. They were observed to be in very good condition. 230 kV lines are located in both Regions. The poles observed had some checking and bleaching, but considering the age of the facilities this was considered normal. Pole tags were present indicating regular inspections by JCP&L.

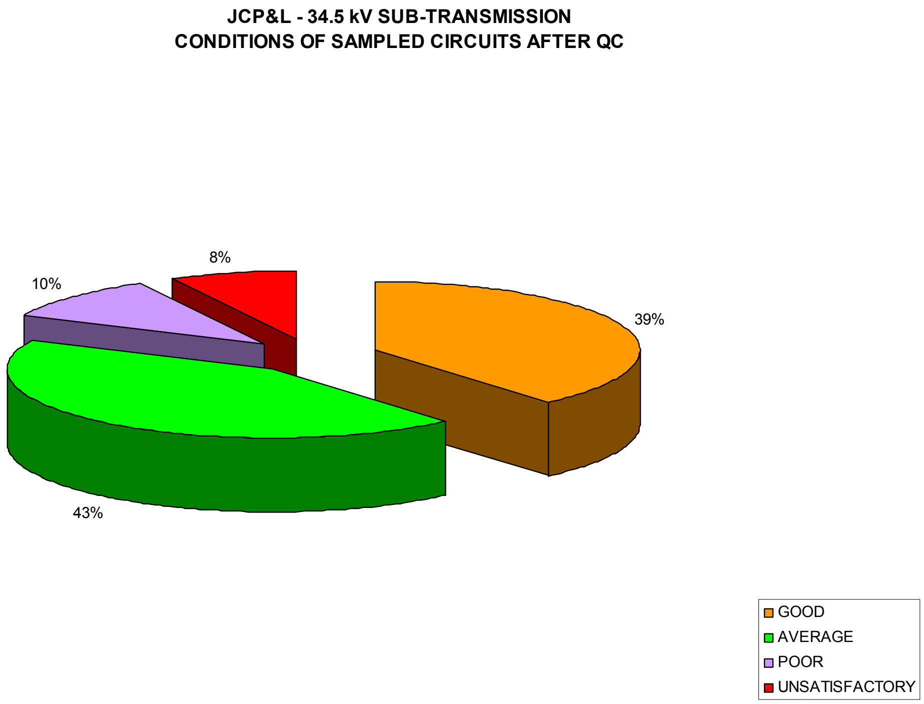
The 115 kV transmission facilities observed in both the Northern and Central Regions were rated average overall. Three below-average locations were noted with one location requiring immediate attention by JCP&L. Circuits B2 and C3 are 1955-vintage lines, and although our Team rated the facilities normal considering the age, a thorough inspection is recommended for these two circuits in the near future. Circuit S-919 equipment inspected showed age deterioration and wood rot. This line is currently scheduled for a detailed "climbing inspection" and maintenance review in 2004. This inspection should be completed on time, which JCP&L has indicated will occur.

Subtransmission Facilities

JCP&L has 1,494.29 miles of 34.5 kV subtransmission facilities, the majority carried on wood poles. Two submarine cables supply the Barrier Peninsula. JCP&L's 34.5 subtransmission facilities operate as the basic primary network for the system. All but 14 power transformers in the system operate at a high side voltage of 34.5 kV. Operation of the 34.5 kV facilities is controlled from the Morristown Regional Dispatch Office but coordinated with the Reading Transmission Dispatch Facility.

A total of 518 poles carrying 34.5 kV facilities were inspected during our condition assessment. These poles were spread over a total of 19 circuits in both the Northern and Central Regions. Overall, the 34.5 kV system can be rated as satisfactory. Figure 1 below shows the condition of the sampled facilities:

Figure 1



Eight percent (8%) of the sampled facilities were observed to be unsatisfactory and in need of immediate attention. Ten percent (10%) of the facilities were observed to be poor, requiring maintenance and/or replacement in the near future. Appendix B contains our Engineers' written evaluation of the 34.5 kV subtransmission circuit inspections conducted during our condition assessment. Also included are photographs and summary discussions for all locations rated as unsatisfactory or poor. The final section in Appendix B is a cost estimate projecting the total material and labor costs required to repair or replace facilities observed to be in unsatisfactory or poor condition.

Of the 518, 34.5 kV subtransmission poles inspected, we identified 40 that needed to be replaced due to age, deterioration or rot. That reflects about 8% of the poles inspected. We did not have an exact number of subtransmission 34.5 kV poles from JCP&L. Assuming 1,494 miles of 34.5 kV subtransmission lines inspected and 290 feet for an average span length, we estimated 26,890 poles were associated with 34.5 kV. On a pro-rata basis, 1,882 would need to be replaced in the near term. Again, this number is not exact but it does provide a magnitude of the percentage of poles that need replacing. Trying to identify one cost associated with the replacement of a 34.5 kV subs-transmission pole was impractical if not impossible. The factors involved with replacing these poles vary a great deal. In an effort to estimate a reasonable replacement cost, the poles were grouped in three types: Type 1, Type 2 and Type 3. Each type was priced based on the average complexity and difficulty to replace the poles. On a pro-rata basis, 1,187 poles were grouped as a Type 1 replacement (Photo 1):

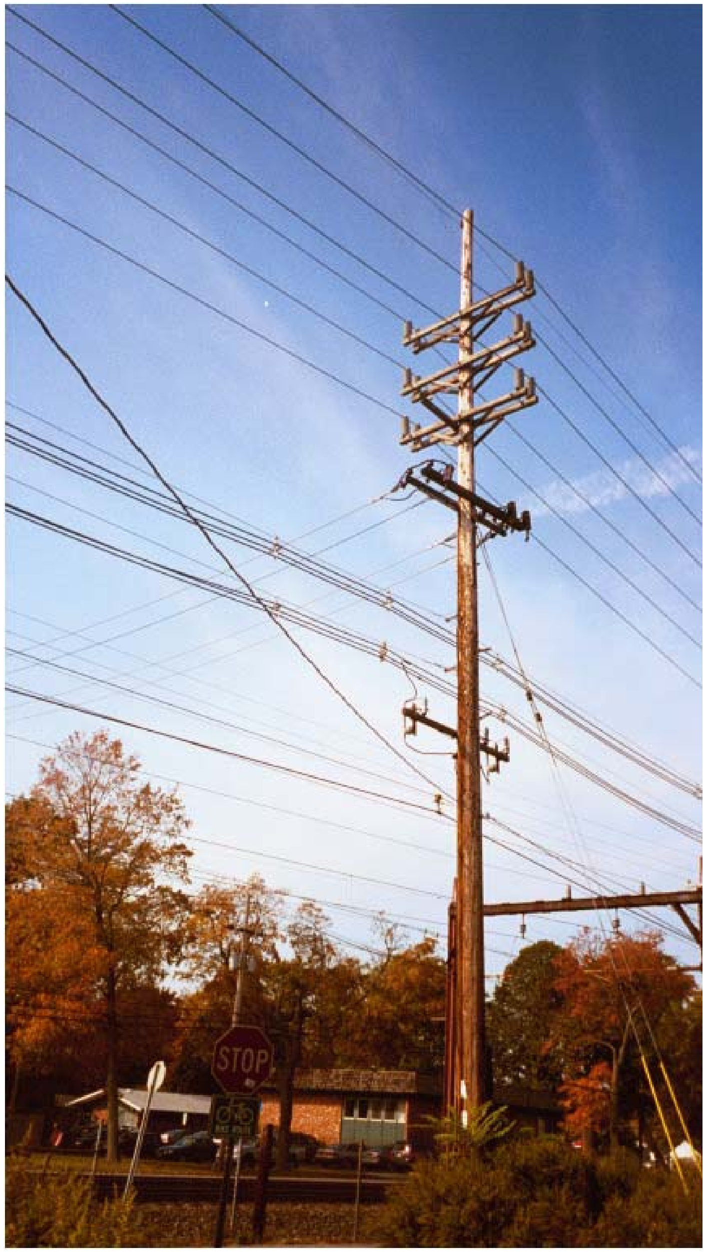
Photo 1

568 poles as a Type 2 replacement (Photo 2):

Photo 2

and 155 poles as Type 3 replacement (Photo 3).

Photo 3



In addition to pole replacement, some cross arms were identified as needing replacement while the poles to which they are attached appear to be solid. The total cost system wide to do this repair/maintenance work is estimated to be $32,311, 626 (See Table 1 in Appendix B).

For the 34.5 kV facilities we inspected, there appear to be three major problems resulting from JCP&L's design and maintenance policies:

1. Poles are allowed to remain in service even when there is significant surface damage or pole rot. Many of the poles inspected have been damaged by vehicles. Excessively damaged poles need to be replaced if reliability is to improve. Damaged poles have a higher probability of failure should vehicle accidents occur to these poles, or windstorms and ice storms occur in the area where they are located.

2. Our inspection revealed that construction standards have not been used for guying of angle and dead-end structures. Use of extremely short guy leads has caused excessive pole buckling.

3. JCP&L has used surge arresters on the top phase for lightning protection instead of using a separate overhead static wire to protect the system. While this does provide some form of lightning protection, it will not allow the subtransmission line to operate uninterrupted in the event of a lightning strike to the top phase. This design can also produce unnecessary problems at substations if breakers are not properly relayed. In the 34.5 kV Coordination Project contained in the ARIP Initiative, the 34.5 kV Design Standards were reviewed and JCP&L determined that "going-forward they will make use of lightning arresters or overhead static wires on 34.5 kV." It is our recommendation that lightning protection be installed on the entire 34.5 kV network. A Dominion Power standard developed as part of a FERC 206 complaint proceeding in the 1990s would serve as a good example for appropriate 34.5 kV lightning protection.

JCP&L should evaluate the selective upgrade of its 34.5 kV to 115 kV for improved:

- Capacity (short and long term)
- Reliability
- Power Loss Improvement

This will be discussed in greater detail in Section 7 and our review of substation planning. With respect to the 34.5 kV system, Paragraph 7 of the MOU and, to the extent that JCP&L agrees to fully comply with its Asset Management Strategy (AMS) document including the CRI program, which agreement is reflected in the Stipulation of Settlement (which includes the published AMS to which JCP&L has agreed to abide) entered into on June 8, 2004 by JCP&L and Board Staff (and which was reviewed and adopted by the Board) addresses this concern.

Substations

Much attention has been given JCP&L's substation facilities since the failure of transformer bushings at the Red Bank Substation during the extreme heat wave experienced in July 1999. The order in Docket No. EA 99070985 required the utility to inspect every transmission and distribution substation on the JCP&L (GPU) system. JCP&L's Compliance Response showed the following results from the Company's visual inspection of its substations:

Table 5
Result of 2000 Visual Transformer Inspections

	North	Central	Total
Total Transformers	295	331	626
No Action Required	197	211	408
Address During Next Scheduled PM*	59	44	103
CM** to be Performed within One Year	39	77	116

* *Preventive Maintenance (PM)*
** *Corrective Maintenance (CM)*

Based on our review of the Corrective Maintenance Orders Summary, only six (6) transformers at the Airfield Substation were scheduled for replacement as a result of the inspections. The remaining actions were corrective maintenance such as repairing and replacing fans, repairing or replacing bushings, checking oil levels, repairing oil leaks, repairing or replacing gauges, and similar preventive maintenance work that should have been detected and corrected during the annual inspections required in the GPU Substation-Oriented Reliability Program.

Booth & Associates, Inc. engineers inspected the following substations selected at random from each operating region. This sample represented approximately ten percent (10%) of the 284 substations on the JCP&L system:

Table 6
Substations Inspected During Condition Assessment

Northern Region	Central Region
Whippany Flanders Changebridge Hamburg East Newton Blairstown Furnace Brook Frenchtown Rocktown Road Rosemont Gilboa Flemington	Atlantic Highlands Smithburg Cheesequake Belford Spotswood Lakewood Motts Corner Waretown Upton Lakehurst Rumson Larrabee

Appendix C contains our Engineers' written comments of the substation inspections.

Substation equipment on the JCP&L system is older than we normally observe on other electric utilities in the 38 states Booth provides services. The following *Figure 2* shows transformer ages for the Distribution Transformers located in the Northern Region:

Figure 2
Distribution Transformer Age
JCP&L Northern Region

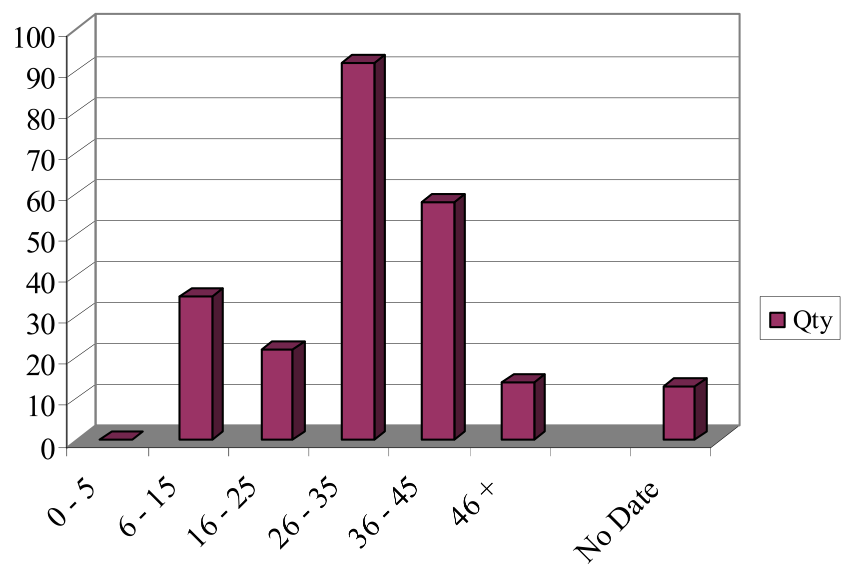
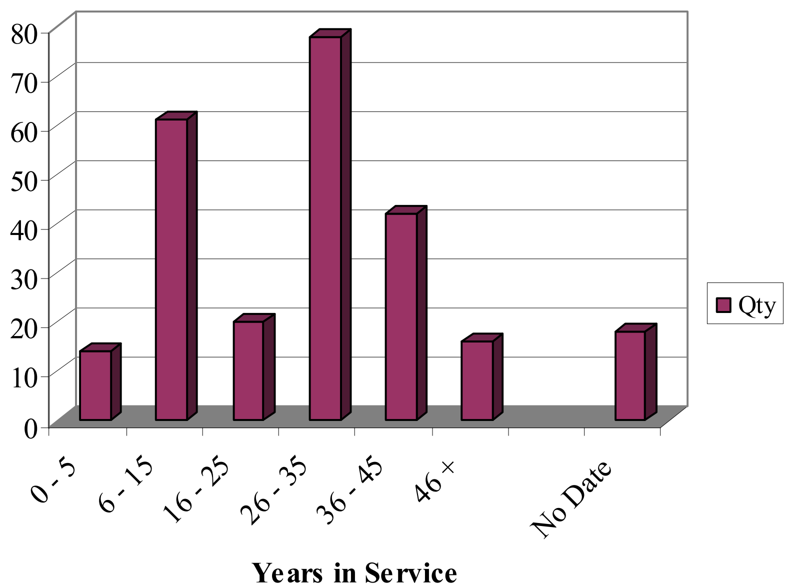


Figure 3 shows similar information for the Central Region:

Figure 3
Distribution Transformer Age
JCP&L Central Region



General Observations

Through our inspection process we discovered that each of the substations we chose graded out in the 'Average' range, save the Smithburg 500kV station in the Central Region and Whippany 230kV station from the Northern Region. These two stations are rated as 'Good'.

In general, we found the substation sites to be clean and well taken care of. It is obvious that good maintenance practices are upheld throughout the stations. We noted that in particular station batteries were in good shape and well maintained.

Although in many cases the equipment was dated, it appeared in good working order. Average year of manufacture for each transformer bank in sampled substations is 1974, however the clear majority of the transformer banks were built in the 1960s (See Appendix C). Similarly, the average age of circuit breakers in use on their system is 1976. (See Appendix C) On average, the circuit breakers in the Central Region are 8 years older than their counterparts in the Northern Region.

Concrete oil containment systems were found in only two stations. Mott's Corner and Larrabee are the lone exceptions. Elsewhere, gravel berms, considered as secondary containment, are relied on for the purpose of compliance with federal regulations on Spill Prevention, Containment and Countermeasures.

Safety

Fences and Grounding Issues

Jersey Central Power & Light Company practices for grounding substation fences does not meet National Electrical Safety Code (NESC) requirements and industry standards resulting in a safety hazard to the public and to its employees. The design and installation of the ground grid system in a substation is meant to reduce dangerous touch and step voltages to safe levels in the event of a fault in the station. A safe "step voltage" means that the voltage difference between the feet of a person walking across the substation during a fault event will not be at dangerous levels. Safe "touch voltage" means the voltage difference from a person's feet and their point of contact with a structure, fence, or piece of equipment will remain at safe voltage levels during a fault event. Per the ANSI/IEEE Std 80 – IEEE Guide for Safety in AC Substation Grounding [Std 80 Section 16.3] the most dangerous touch voltages occur on the substation fence. For this reason the NESC calls for bonding of the fence and the barbed wire strands at the top of the fence [092.E]. NESC 092.E.4 states "If barbed wire strands are used above the fence fabric, the barbed wire strands shall be bonded to the grounding conductor, jumper, or fence." JCP&L in its past and present practices only connect the fence posts to the ground grid at typically 30' intervals. JCP&L does not extend bonding conductors to the barbed wire at the top of the fence and relies on the fence posts for bonding of the fence fabric. Appendix C contains a copy of the NESC Interpretation Booth relied upon for our determination. Our opinion and that of the NESC interpretation committee is that bonding of the barbed wire is required to meet code and not simply a recommendation of exceeding the code requirements. JCP&L should follow the NESC standards, including the published IEEE committee interpretations. JCP&L employees and the public who are in proximity to an improperly grounded substation fence during an electrical fault involving a substation could be subjected to life threatening voltages. JCP&L has agreed in the MOU to seek and abide by interpretive guidance from IEEE regarding this issue. Accordingly, this issue has been addressed.

Our examination of JCP&L substations showed three installations were especially troublesome with regard to the safety of the public and JCP&L employees. Two of the installations, Rosemont and Flemington Substations, involved temporary transformer connections along with temporary substation fencing and at one station, Cheesequake, there was no fence at all. The problems at the Rosemont, Flemington, and Cheesequake substations were corrected by JCP&L after our Audit brought the problems to JCP&L's attention.

The disconnection of the old transformer and the connection of the temporary transformer at the Rosemont substation in the Northern Region was done in a manner that poses great risk to the public and to JCP&L employees. High voltage conductors were disconnected from the old transformer and the transformer was left in place; but the transformer's bushings were not grounded per industry standard safety practices. (NESC Rule 123 and OSHA 1910.269[n]). A person standing on the ground in the station could easily touch the transformer low voltage bushings. With the old transformer directly under an energized bus it is very likely that dangerous levels of voltage are stored in the transformer which could be discharged causing injury to a person who comes in contact with the transformer bushings. Grounding all the high voltage bushings in a disconnected substation transformer prevents the build up of unsafe voltages. A temporary fence erected around the temporary transformer was not grounded at all. Only the temporary transformer was grounded to the existing ground grid. The temporary fence without proper grounding could cause serious injury to someone in proximity to the fence if an electrical fault occurred. When these items were pointed out to the supervisor of substation maintenance, he was unaware of the safety hazards posed by the disconnected transformer and the lack of grounding on the temporary fence. Though this is in an isolated rural setting, there is a residence directly across the street.

At the Flemington Substation work was in progress that required the installation of a mobile substation. The temporary fencing around the mobile substation had several deficiencies creating dangers to the public and JCP&L employees.

1) The temporary fencing was not grounded. (NESC and OSHA requirement)
2) Sections of fence were not joined together securely. (Only one metal clamp and one plastic wire tie were used to join two adjacent fence posts together.)
3) The fence was installed too close to the mobile substation, which would allow sticks or other objects be inserted through the fence fabric and come in contact with the mobile substation.

Flemington was easily accessed through a local business parking lot adjacent to the substation. The temporary fence at the Flemington Substation would not easily deter unauthorized access into the substation. As described before the lack of fence grounding presents a hazard of unsafe touch voltages involving the temporary fence during a fault condition.

At the Cheesequake Substation no perimeter fence exists around the metalclad breakers and transformers. Instead a collection of fence partitions located between the switchgear and transformers are used to limit access. There were areas where it would be easy for animals to crawl under the high side metalclad switchgear, which is mounted on short, raised, concrete piers. Installations such as this may be observed within industrial complexes with perimeter fencing and limited access. It was mentioned that Jersey Central was in the process of clearing the area for the installation of a new perimeter fence surrounding the substation. The risk of unauthorized access to this substation is high without the completion of the perimeter fence.

RECOMMENDATIONS

1. Standard industry practices call for seven-foot (7') fences (including 1' barbed wire) and bonding the fence posts, fence fabric, and barbed wire to the substation ground grid system. We recommend that all substation fences comply with the standards and fence posts, fence fabric and the barbed wire at the top of the fence be bonded to the substation ground grid conductors. This additional grounding will help protect the public and JCP&L employees from dangerous voltages in the vicinity of the substation fence during an electrical fault.

   Paragraph 2 of the MOU, which provides that JCP&L will request a rule interpretation from the IEEE, addresses this recommendation.

2. JCP&L should prepare a safety program addressing correct substation grounding practices, placing emphasis on fencing and transformer grounding. All field and engineering employees, and contract workers should attend this safety class in the year 2004.

   Paragraph 9 of the MOU, which provides that JCP&L will address training related to substation grounding design practices for appropriate employees, addresses this recommendation.

3. JCP&L should assess the adequacy of the substation grounding, counterpoise and perimeter fence grounding at all of its substations utilizing the IEEE standards. JCP&L was unable to direct us to any documentation on prior or existing calculations or tests as required by the NESC and prudent utility practice. Enhancement of substation grounding will not only improve safety, it will also enhance reliability and equipment performance.

   Paragraph 2 of the MOU, which provides that JCP&L will request a rule interpretation from the IEEE, addresses this recommendation. Paragraphs 10 and 11 of the MOU (described below) also address aspects of this recommendation.

4. JCP&L should perform follow up inspections of their facilities to ensure correct grounding practices are followed. The safety problem at Rosemont concerning the out-of-service transformer should be corrected immediately by grounding the bushings.

   Paragraph 10 of the MOU, which provides that JCP&L will, among other things, continue to include substation grounding as part of its monthly substation inspection process and will continue to ground out-of-service equipment, addresses this recommendation.

5. At the Upton substation, a notice was posted on the high-side steel structure stating "Must Wear High Voltage Boots When Switching." When asked what this sign meant, the response was the substation ground grid had been tested and found to have unacceptable touch potentials. This type of testing should be performed at all substations to verify that the existing ground grid is adequate. Based on comments it would appear this was the first substation where it was determined unacceptable potentials could occur for faults. It is recommended that "old" substations with limited ground grids be tested in accordance with IEEE Std 80 to verify resistance for ground values required for safety and to determine that grounding continuity exists for all equipment grounding connections.

   Paragraph 11 of the MOU, which provides that JCP&L will provide a report to the NJBPU Staff about the various methodologies that are available to test the integrity of the ground grid, addresses this recommendation.

   In addition, as indicated above, the problems at the Rosemont, Flemington, and Cheesequake substations were corrected by JCP&L after our Audit brought the problems to JCP&L's attention.

Warning and Danger Signs

JCP&L has an adequate number of signs on fences, steel structures, and equipment inside the substations we inspected. However, most of the signs do not conform to the latest sign standards. All new and replacement signs need to be installed in accordance with the latest National Electrical Safety Code (NESC) and ANSI Z535 sign, tag, and label standards. They should also comply with the latest Occupational Safety and Health Standards. The majority of the substations visited did not have signage reflecting these latest standards. It is important that the signs are capable of being easily read and understood and fully comply with the most current editions of NESC, OSHA, and ANSI.

Many JCP&L substation signs were prematurely faded, small, and with limited information and effectiveness. Danger stickers on structures are small and the red color around the word "Danger" is faded on those stickers facing east, south, or west. The standards are very specific concerning readability of signal words (message) and viewing distances. Also, it is industry standard practice to place "Warning" signs on the fence, "Danger" signs on structures, and signs with emergency contact information on the gates.

RECOMMENDATION

We recommend that JCP&L's new replacement signs be installed in accordance with the latest ANSI Z535 standards and OSHA standards in conjunction with updating their material specifications calling for quality, long-life materials. Twenty-year ratings are available that cover fading and cracking of material. These signs should emphasize action, use proper signal words and colors, show emergency information, and be bilingual if appropriate.

Paragraph 12 of the MOU, which provides, among other things, that as JCP&L replaces faded or cracked or otherwise unreadable signs on its substation fences and gates, it will do so with signs that comply with the latest ANSI 2535 and OSHA standards and that all new signs will also comply with the latest ANSI 2535 and OSHA standards, addresses this recommendation.

Operations

Power Transformer Loading

Power transformers are the largest capital investment item in a substation. The cost of unexpected failure can be several times the initial cost of the transformer. Not only is there the cost of transformer repair or replacement, but the costs of clean up, lost revenue, damage to adjacent equipment, litigation, and environmental issues. Hartford Steam Boiler, a major insurer of electrical power equipment, states transformers can be expected to last 40 to 50 years. Some utility engineers believe the maximum useful life of a power transformer is 40 years. As transformers age, the probability of failure rises. The utility's challenge is to predict the expected end of life of its transformers and take the actions necessary before the transformer fails. The expected life must be determined based on historical information, engineering analyses, testing and diagnostics, correct interpretation and application of standards, and operating the transformer within its thermal limits. ANSI/IEEE and other international standard organizations provide specific guidelines and direction for loading transformers above nameplate.

Based on the JCP&L's transformer database, two hundred and sixty six (266) of the four hundred and eighty three (483) total transformers are more than 30 years old with one transformer, the Stewartsville Substation transformer, that is 52 years old. This aging population creates a serious challenge for the utility to meet future demand for electricity and maintain system reliability. Since transformer failure is an eventuality, an action plan must be put in place to reduce the likelihood of transformer failure. The statement "If you cannot measure it, how can you manage it?" is especially true for transformers. Transformers may show little evidence of problems until it is too late unless steps are taken to identify problems before they become failures.

The loading of power transformers above nameplate rating has serious consequences when applied without knowledge of the condition and thermal characteristics of the transformer. Based on the transformer data provided for the Central and Northern Jersey Central regions, 58 substation transformers are operated above their nameplate rating at times, which represents more than 12% of JCP&L's 483 substation transformers. Thirty-nine (39) of the fifty-eight (58) transformers are 30 years or older.

In the Northern New Jersey Region, 33 substations are involved:

Table 7
Selected Substations Northern Region

Substation	Name Plate (MVA)*	All Time Peak (MVA)*	Percent Above Nameplate
Air Reduction-Bank 1	20.0	21.8	9%
Air Reduction-Bank 2	20.0	20.6	-
Alderney	20.0	23.3	17%
Allamuchy	9.3	11.7	25%
Bernardsville	20.0	21.3	6%
Blairstown	9.4	11.4	21%
Boonton	6.3	6.5	3%
Branchville	9.4	9.5	2%
Broadway	8.4	8.5	2%
Change Bridge	20.0	22.0	10%
Chapin Road	20.0	18.0	-
Chester-Bank 1	20.0	22.6	13%
Chester-Bank 2	20.0	20.35	-
Flanders-Bank 1	20.0	21.83	9%
Flanders Bank 2	20.0	22.38	12%
Gillette	9.4	10.1	7%
Greater Cross Road	20.0	21.8	9%
Green Village	9.4	10.5	12%
Hackettstown	9.4	11.4	21%
Hawks	9.4	12.0	27%
Hurdtown	9.4	11.0	17%
Kenvil	20.0	20.2	1%
Morristown	50.0	56.6	13%
Ft. Fern	9.4	10.8	15%
Mt. Pleasant	20.0	15.6	-
Newburgh-Bank 1	20.0	20.8	-
Newburgh-Bank 2	20.0	23.2	16%
North Branch	20.0	20.7	4%
North Newton	9.4	11.4	21%
Riverdale	9.4	11.5	23%
Rocktown Road	9.4	12.3	31%
Stanton-Bank 1	6.3	6.5	3%
Stanton-Bank 2	9.4	8.9	-
Stewartsville	4.7	4.8	2%
Sussex	9.4	10.0	7%
Traynor-Bank 1	9.4	8.3	-
Traynor-Bank 2	9.4	8.7	-
Traynor-Bank 3	20.0	13.7	-
Washington	9.4	10.0	6%
Woodruffs Gap	4.7	1.6	-

* - Nameplate MVA and peaks in table are rounded, the calculation of percentage is based on exact levels.

In the Central New Jersey Region, 30 substations are involved:

Table 8
Selected Substations Central Region

Substation	Name Plate (MVA)*	All Time Peak (MW)*	Percent Above Nameplate
Air Field	6.0	6.1	2%
Belford	9.4	10.1	7%
Belmar	9.4	11.0	18%
Clark Street	9.4	8.0	-
Colonial Oaks	9.4	11.0	17%
Crawfords	20.0	17.6	-
Fair Haven	9.4	11.3	21%
Fairview	9.4	7.8	-
Howell	20.0	19.0	-
Hyson (2)-Bank 1	20.0	21.0	5%
Hyson (2)-Bank 2	20.0	25.3	26%
Island Heights	20.0	18.5	-
Jamesburg	6.0	2.4	-
Jerseyville (2)-Bank 1	7.5	8.2	9%
Jerseyville (2)-Bank 2	20.0	21.7	8%
Lacey	20.0	22.7	3%
Lavallette	9.4	10.2	8%
Mantoloking	9.4	9.9	5%
Mcgraw Hill	9.4	7.4	-
Millhurst	20.0	20.7	4%
Monmouth Beach	7.5	9.2	23%
Motts Corner	9.4	12.2	30%
Ocean Beach	9.4	9.8	4%
Old Bridge	20.0	22.2	11%
Ortley Beach	6.3	7.8	23%
Pine Beach	9.4	10.1	7%
Pleasant Plains	20.0	20.3	2%
Seaside Park	7.5	7.6	1%
Taylor Lane	20.0	15.6	-
Whitesville	5.0	5.3	6%
Woodbine	20.0	17.9	-
Woodland (2)-Bank 1	9.4	10.8	15%
Woodland (2)-Bank 2	20.0	21.8	5%

* - Nameplate MVA and peaks in table are rounded, the calculation of percentage is based on exact levels.

Based on data collected in the field and conversations with Jersey Central personnel, all Jersey Central transformers are rated 65°C winding rise insulation. Thus a transformer can operate with normal life expectancy at maximum temperatures of 110°C, which is the sum of the following temperatures: 86°F (30°C) (ambient) + 65°C (avg. winding rise) + 15°C (hot spot rise) when fully loaded at the nameplate ratings. Of course, maximum allowable hot spot and top oil temperatures can not be exceeded. It should be noted Jersey Central's ambient summertime temperatures sometimes exceed 100°F (38°C).

Normal life expectancy under these conditions of loading (a continuous winding hottest-spot of 110^{o} C) is defined by ANSI (C57.91-1995) as 6.5 x 10^4 hours, a daily normal loss of life of 0.0369%. Aging calculations at other than rated temperatures are determined using computer programs or equations found in the ANSI Standards. Of course the actual life should be considerably greater since transformers are not normally loaded at or near their rated capability. Thus, transformers typically have a normal life expectancy of 40 or more years. However, a transformer's insulation life is a function of time and temperature. Capability (Loss of Life) tables are included in ANSI/IEEE C57.92-1981 (this standard has been consolidated with C57.91-1995) showing percent loss of life for various combinations of time and continuous temperature.

The FirstEnergy Planning Criteria for transformers are contained in 4.0 Transformer Ratings and 4.1 Local Transmission:

> "Emergency transformer ratings at GPU are developed using the PJM transformer heat run program, and include a six month rating, a one month rating, a one week rating, a 24 hour rating, four hour rating, and a one hour rating. The one-hour rating corresponds to a hot-spot temperature of 180^{o} C. The other ratings are based on a hot-spot temperature of 140^{o} C." The assumed 24-hour average summer ambient of 35^{o} C and the average summer normal rating is 118% of the top nameplate rating. It should be noted that normal transformer rating is 100% of the top nameplate rating, nothing higher."

An example using the planning criteria shows the potential impact on transformer operation for a typical transformer during the summer months on the JCP&L system. For a 20/26.6/33.3 MVA transformer loaded according to the FE guidelines, our analysis using the equations found in the ANSI standards referenced above shows that the transformer loss of life is 6.78 times greater than normal loss of life. In addition, operating at the FE criteria, the oil temperature exceeds recommended ANSI values, which can cause a premature dielectric failure.

Application of the planning criteria for this example is as follows: The substation contains a 20/26.6/33.3 MVA transformer loaded to 39.33 MVA (assumed 118% of the top nameplate rating) and average summer ambient of 35 ^{o} C for 24 hours. The hot-spot temperature reaches 140 ^{o} C and the top-oil temperature 121 ^{o} C with a 0.25% loss of life or 6.78 times faster than normal loss of life. At this loading the transformer is expected to last 400 days. Since the top-oil temperature should never exceed 110 ^{o} C, the study was redone to limit top-oil temperature to 110 ^{o} C. This limitation is due to problems associated with free bubble evolution created by moisture inside the transformer. To limit the top-oil temperature, the transformer study was repeated using top-oil temperature of 110 ^{o} C. Ignoring the top-oil temperature is very dangerous due to possibility of creating flashover inside the transformer tank. The results of new computer run are the transformer is load limited to 36.34 MVA (109% of the top nameplate rating) with hot-spot temperature of 128 ^{o} C and a 0.074% loss of life, approximately twice that of normal loss of life.

It is critical that the transformer loading policy/guidelines are based on transformer's nameplate rating as determined by an extensive evaluation of the transformer's specific design, equipment condition, an acceptable loss of life risk, maintenance records, and oil and winding temperature monitoring. Any substation transformer loaded beyond nameplate should be monitored on real-time basis. The substation visited did not appear to have remote monitoring of the transformer temperatures.

As indicated in the Executive Summary, Booth & Associates, together with Board Staff and the Company engaged in an iterative process which made significant progress towards addressing all recommendations and, insofar as the issues discussed above are concerned, to the extent that JCP&L agrees to fully comply with its Asset Management Strategy (AMS) document including the CRI program, which agreement is reflected in the Stipulation of Settlement (which includes the published AMS to which JCP&L has agreed to abide) entered into on June 8, 2004 by JCP&L and Board Staff (and which was reviewed and adopted by the Board), which resolves these concerns.

Transformer Life Cycle Program

To operate above nameplate, it is imperative that steps be taken to ensure that the transformer is not operated at temperatures greater than those allowed for the condition of the transformer and allowed by the transformer standards. (ANSI-C57.91 – 1995)Operating above nameplate requires that proper precautions be taken to identify those transformers that are at risk of developing problems. A strategic life cycle transformer management program must be in place to establish loading limits. A transformer management program must provide the following steps to determine suitability of the transformer:

1. Step 1 is an engineering analysis of the transformer's age, manufacture, vintage, materials, short-circuit strength, operating environment, past usage, and results of oil tests and test diagnostics.
2. Step 2 is an assessment of the condition of the transformer both internal and external to check the cooling system, bushings, lightning arresters, tank, LTC controls, and when possible the coils and clamps, leads and paper, and LTC and NLTC switches.
3. Step 3 is annual oil testing and diagnostics such as Doble testing. Monitoring of critical transformers should be a consideration.

4. Step 4 is benchmarking results for comparison of the baseline data to changes indicated by oil testing and diagnostics.
5. Step 5 is to establish acceptable loss of life limits and loading policy for each transformer using the information from steps 1 through 4.

The utility's loading policy should provide a measure of an acceptable loss of life limit for each transformer. Following are some of the issues to be considered to determine how much risk to assume when loading aging power transformer above nameplate:

1. Prior to 1967, transformer engineers used conservative designs since they lacked the advanced computer design software to control transformer leakage flux and hot spots. They also did not have the tools necessary to meet today's short circuit requirements. The bushing lead capacity is often a major loading limitation.
2. Prior to late 1960's, thermally upgraded insulation was not available; thus, transformers manufactured prior to late 1960's are more susceptible to insulation degradation from heating and moisture. Moisture is a transformer's worst enemy.
3. Age affects the ability of a transformer to withstand stress. The aging effect reduces both the transformers' mechanical and dielectric withstands strength. As the unit ages, system stresses normally increase due to load growth, distribution faults, lightning, frequent switching operations and other electrical disturbances. The combination of these tends to increase the chances of failure.
4. Loading beyond nameplate rating during excessive ambient or partial cooling may result in sustained transformer temperatures, possibly degrading the winding insulation.
5. Transformer protection provided by power fuses provide little protection against transformer incipient faults, which increase the risk of transformer failure.
6. Prior to the mid 1970's transformer materials were of a lower design quality and not as technologically advanced as present-day transformers.

Paragraphs 17, 18, 19 and 20 of the MOU address specific substations and or transformers and provide an increased focus on monitoring and data collection and assessment. We believe that this represents a very positive step towards addressing some of the concerns we have otherwise indicated in this report about the Company's transformers. Moreover, as indicated in the Executive Summary, Booth & Associates, together with Board Staff and the Company engaged in an iterative process which made significant progress towards addressing all recommendations and, insofar as the issues discussed above are concerned, to the extent that JCP&L agrees to fully comply with its Asset Management Strategy (AMS) document including the CRI program, which agreement is reflected in the Stipulation of Settlement (which includes the published AMS to which JCP&L has agreed to abide) entered into on June 8, 2004 by JCP&L and Board Staff (and which was reviewed and adopted by the Board), which resolves these concerns.

RECOMMENDATION

It is recommended that the utility adopt a life cycle transformer management program

(1) Consisting of an engineering review of all of the transformers on the system,
(2) Performing a condition analysis for each transformer,
(3) Strengthening the maintenance program by benchmarking all oil and diagnostic testing to detect abnormal conditions early, and
(4) Establishing a company loading policy that is good utility practice.

Implementing these recommendations, Jersey Central will be able to extend transformer life and make informed decisions as to when to replace existing transformers before a costly failure. Given the utility's practice of regularly overloading its transformers, and the overall age of the transformers, the utility needs to prepare for losing many of their 30+ year old transformers within the next ten years. Thus, it is imperative that an action plan be established to replace these older transformers. Therefore, it is recommended that:

(1) The utility budget and purchase new transformers for replacements each year for ten years, based on full testing and assessment.

(2) The utility implement a life cycle transformer management program.

JCP&L has nine (9) transformers more than 50 years old that need to be replaced immediately and forty-seven (47) that are in the 40 to 50 year age bracket. They should be given immediate attention given their increased possibility of failure due to age. To the extent any of these transformers appear in Tables 7 and 8, they should receive first priority for replacements. For the remaining transformers shown in Tables 1 and 2, load transfer or load sharing should be used to the extent possible to relieve overloading.

Paragraphs 17, 18, 19 and 20 of the MOU, which address specific substations and or transformers that are found in Tables 7 and 8 provide, among other things, an increased focus on monitoring and data collection and assessment, address this recommendation. Paragraphs 17, 18, 19 and 20 of the MOU address specific substations and or transformers and provide an increased focus on monitoring and data collection and assessment. We believe that this represents a very positive step towards addressing some of the concerns we have otherwise indicated in this report about the Company's transformers. Moreover, as indicated in the Executive Summary, Booth & Associates, together with Board Staff and the Company engaged in an iterative process which made significant progress towards addressing all recommendations and, insofar as the issues discussed above are concerned, to the extent that JCP&L agrees to fully comply with its Asset Management Strategy (AMS) document including the CRI program, which agreement is reflected in the Stipulation of Settlement (which includes the published AMS to which JCP&L has agreed to abide) entered into on June 8, 2004 by JCP&L and Board Staff (and which was reviewed and adopted by the Board), which resolves these recommendations.

The planning section of this report addresses additional substation capacity standards to be implemented.

Distribution Feeders

Typical configuration of both existing and new JCP&L substations have two (2) feeders for each transformer regardless of transformer size. When the substation transformers were smaller, typically 7.5 MVA, this resulted in less than 4 MVA of load on each feeder circuit. As substation transformers have gotten larger, JCP&L retained the practice of utilizing just two (2) feeders per transformer. On average each power transformer in JCP&L substations serves 2.16 feeders (See Appendix C). The larger substation transformers combined with the regularly overloading of substation transformers means that individual circuits could be loaded up to 10 MVA.

The heavy loading of individual feeder circuits degrades the reliability of the electric system. When problems occur on an individual feeder twice the number of customers are affected than would be if the circuit were loaded to more reasonable levels. This combined with poor practices for sectionalizing tap lines means that all customers on a feeder circuit are affected by problems that occurs on a circuit. Heavy loading of each feeder circuit means that there is no capability to pickup additional loads during unusual switching conditions such as when a substation transformer fails. Problems on heavily loaded feeder circuits affect more customers for longer periods of time.

RECOMMENDATION

JCP&L should move its planning, substation design, and operation criteria to increase the number of circuits for the system at least 50%. This requires adding additional feeders to substations with transformers larger than 10 MVA. This practice will reduce the number of customers affected by individual circuit problems and reduce overall customer outage time when extensive switching is needed to restore load.

As indicated in the Executive Summary, Booth & Associates, together with Board Staff and the Company engaged in an iterative process which made significant progress towards addressing all recommendations and, insofar as the issues discussed above are concerned, to the extent that JCP&L agrees to fully comply with its Asset Management Strategy (AMS) document including, more particularly in this instance, the CRI program, we consider that this recommendation has been addressed. Further, on June 8, 2004 JCP&L and Board Staff entered into a Stipulation of Settlement (including JCP&L's published AMS), that was presented to and adopted by the Board, which resolves this recommendation.

Lightning Protection

Direct strike shielding within substations was almost non-existent. Only the Whippany, Belford, and Smithburg substations had any kind of lightning protection. Lightning is one of the leading causes of power outages as well as transients on utility power lines. Lightning accounts for a quarter of the outages on 230-kV lines, two-thirds of the outages on 345-kV lines and half the outages on circuits up to 33 kV. Most New Jersey areas receive 25 to 30 thunderstorms per year, with fewer storms near the coast than farther inland.

RECOMMENDATION

New Substations

Since the effects of a direct lightning strike to an unshielded substation can be devastating, it is recommended that some form of direct strike protection be provided in future stations. Direct strike protection normally consists of shielding the substation equipment by using lightning masts, overhead shield wires, or a combination of these devices. The types and arrangements of protective schemes used are based on the size and configuration of the substation equipment.

Accepted industry standards require that all stations have a static or shield wire over at least the high side equipment and preferably over the entire station. A single shield wire provides a 30-degree wedge of protection from direct lightning strike to each side of the shield wire as measured from the vertical. This angle may be increased to 45 degrees for areas between shield wires when two or more are used. A single steel mast provides a cone of protection for an angle of 30 degrees from the mast. If more than one mast is used, the angle from the mast may be increased to 45 degrees for areas between the masts. Also, the shield wires or mast must be properly grounded.

Paragraph 7 of the MOU addresses this recommendation. In addition, as indicated in the Executive Summary, Booth & Associates, together with Board Staff and the Company engaged in an iterative process which made significant progress towards addressing all recommendations and, insofar as the issues discussed above are concerned, to the extent that JCP&L agrees to fully comply with its Asset Management Strategy (AMS) document including the CRI program, which agreement is reflected in the Stipulation of Settlement (which includes the published AMS to which JCP&L has agreed to abide) entered into on June 8, 2004 by JCP&L and Board Staff (and which was reviewed and adopted by the Board), which resolves this recommendation.

Existing Substations

We recommend a study of substation outages on JCP&L's system be commenced to determine the impact of lightning on substation operations. Information from the study can be used to determine where static protection is first needed on the JCP&L system. It will also establish the implementation priority for installing static protection in existing stations is warranted.

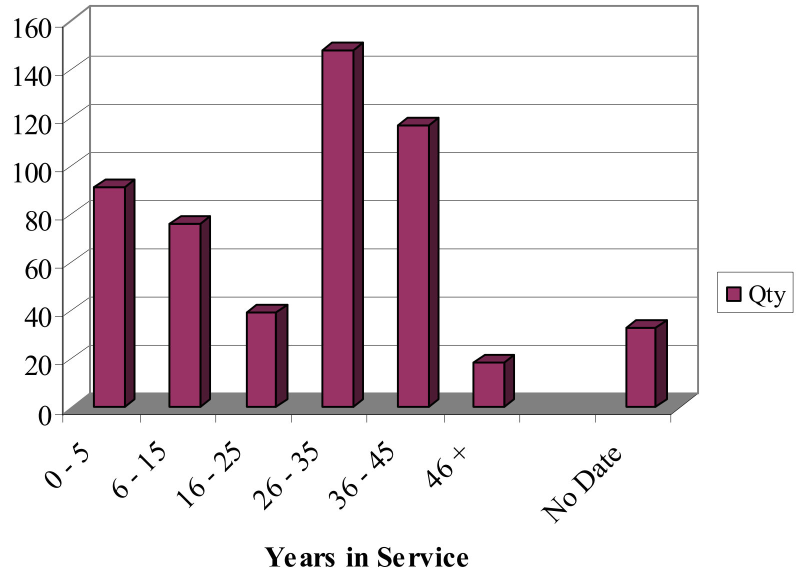
Paragraph 7 of the MOU addresses this recommendation. In addition, as indicated in the Executive Summary, Booth & Associates, together with Board Staff and the Company engaged in an iterative process which made significant progress towards addressing all recommendations and, insofar as the issues discussed above are concerned, to the extent that JCP&L agrees to fully comply with its Asset Management Strategy (AMS) document, including, more particularly in this instance, the CRI program, we consider that this recommendation has been addressed. Further, on June 8, 2004 JCP&L and Board Staff entered into a Stipulation of Settlement (including JCP&L's published AMS), that was presented to and adopted by the Board), which resolves this recommendation.

Overhead Distribution System

JCP&L has 17,278 miles of Distribution lines and 526,903 wood poles. This overhead system is tied to 483 distribution substation transformers by approximately 1,108 circuits operating primarily at 12.47 kV (wye), 4.16 kV (wye), and 4.8 kV (delta). Customers are served from approximately 159,000 pole-mount transformers.

The RFP requested that Booth determine the average age of JCP&L's assets (poles, stations, breakers, distribution wires). Copies of asset databases were not available in order to calculate the average age of all major asset components. *Figure 4* below shows the average age of the circuit breakers in the Northern Region:

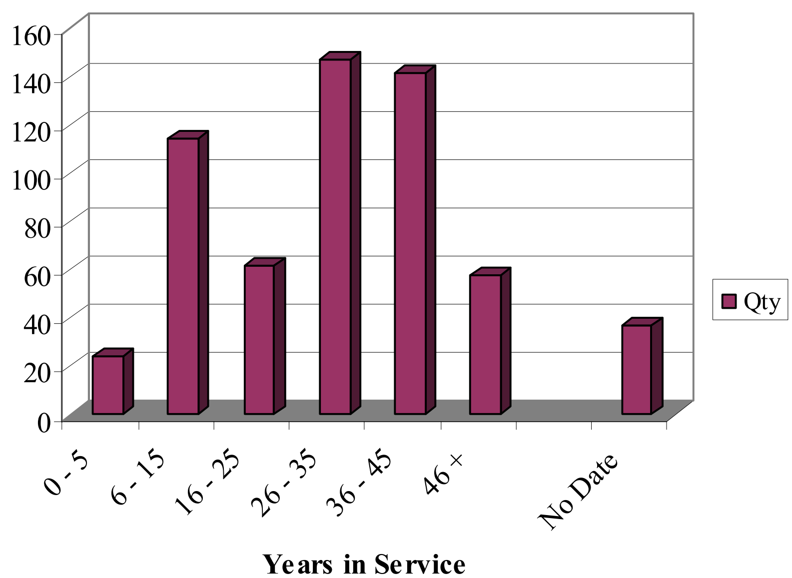
Figure 4
Northern New Jersey Region Circuit Breakers



Fifty-four percent (54%) of the circuit breakers exceed twenty-five (25) years in service.

Figure 5 shows similar information for the Central Region:

Figure 5
Central New Jersey Region Circuit Breakers



For the Central Region, fifty-nine percent (59%) of the circuit breakers exceed twenty-five (25) years in service.

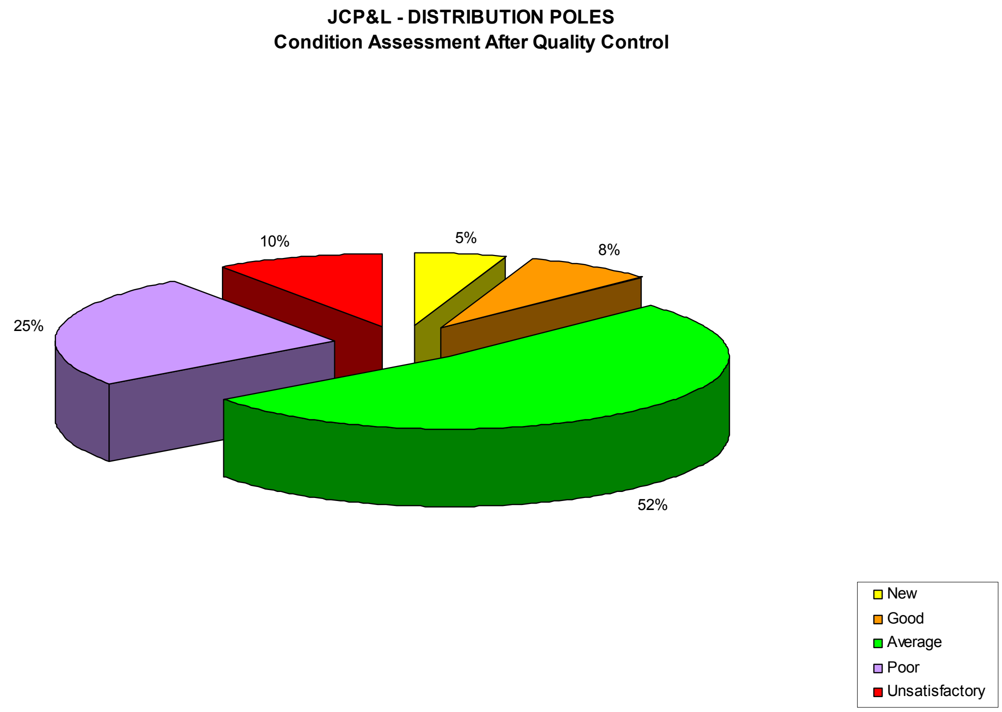
Our teams initially inspected 989 pole locations from five (5) circuits in each region designated as *worst-performing circuits* from the 2002 Annual System Performance Report and five (5) additional circuits in each region chosen at random. As a quality check, our Team then inspected 210 pole locations at two (2) circuits JCP&L identified as their best circuits in each region. Two additional circuits containing underground facilities were inspected after our engineers determined that the original circuits chosen did not contain a sufficient number of padmount transformers. Table 9 summarizes the distribution circuits inspected:

Table 9
JCP&L Circuits Inspected During
Booth Condition Assessment

Distribution Circuits Initially Inspected	
Cranbury	47183
Cranbury	47196
Florham Park	37740
Florham Park	37743
Florham Park	37744
Holiday Lakes	17301
Holiday Lakes	17302*
Lakehurst	69328
Lakehurst	69329
Laurence Harbor	47180*
Laurence Harbor	47181
Mid Monmouth	57363
Mid Monmouth	57364
Mt Arlington	14604
Mt Arlington	17605
Pequannock	33875
Pequannock	37876
Stone Church	57181
Stone Church	57351
Stone Church	57352
West Flemington	24531
West Flemington	27528
Colored Circuits 2002 “Worst Performing List”	
*Appeared on the 2000 “Worst Performing List”	
Distribution Circuits Chosen by JCP&L to be inspected:	
Academy	37954
Lyons	17641
Hooper Avenue	67263
Pleasant Plains	67002

Figure 6 below shows the results of our condition assessment, following the quality control process:

Figure 6



With respect to distribution facilities (poles, conductors, cross-arms, and pole-top transformers), approximately ten percent (10%) of the facilities inspected by our Team Members were observed to be unsatisfactory and in need of immediate attention. Twenty-five percent (25%) of the facilities inspected were observed to be poor, requiring maintenance and/or replacement in the near future. A list of all sampled facilities rated as unsatisfactory or poor, as well as photographs (where available), is shown in Appendix D.

Appendix D also contains our Team Members' written logs and observations during their inspections. A detailed engineering cost estimate is included showing the estimated total material and labor costs required to repair or replace facilities observed to be in unsatisfactory or poor condition.

Of the 1,199 poles inspected in the JCP&L service territory, 10.0 percent required replacement or repair. Based on the percentage of distribution poles inspected, 50,550 require replacement or repair. The total number of poles to be replaced is 38,446. (See Table 2, Appendix D). The total system wide cost to make necessary improvements is estimated at $90,531,520, based on extrapolating the results from the statistical sample.

The estimate to replace a pole was based on the installation of a 45/3 pole and removal of the old pole, transferring one transformer from the old pole to the new pole, and transferring three phase energized conductors and the neutral conductor. The estimate was developed on the basis of an average installation. Some structure replacement will cost more and some will cost less. The $90 million represents the projected cost to bring the distribution poles across the system in both regions up to an average level. This means there will remain some structures below average while there will be structures which are above average.

General Observations of the Distribution System

JCP&L uses an approach towards repair and maintenance of distribution poles which is often temporary in scope rather than completing a permanent repair upon identification of a repair or maintenance need, as shown in Photos 4 and 5.

***Photo 4**:*

Photo 5

The pole in Photo 4 has a considerable amount of surface damage. The pole has been reinforced with a fiberglass splint at the base. This should only be a temporary fix to allow time to replace the pole. The pole in Photo 5 shows another method commonly used by JCP&L to repair a split pole rather than replacing it.

Rotten poles were patched or otherwise temporarily secured instead of completing a permanent replacement. This is certainly not good utility practice and should only be used for emergency situations or for short-term repair.

Pole heights were increased and circuits were added to the top of existing poles by bolting a pole extension (part of a wood pole) to the top of an existing pole. This was done in lieu of replacing the old pole with a taller and larger class (diameter) pole and does not comply with the NESC (Sections 25 and 26). (See Photos 6 and 7) This practice represents a safety and system reliability risk. In most cases it exposes major feeders to higher risk of storm-related outages, including low to medium speed winds up to 50 mph.

Photo 6

Photo 7

Our interviews determined that the staff and construction personnel involved in work order preparation and construction had no knowledge of guying strength requirements, standards, or transverse loading calculations. Poles requiring guys and anchors were also observed without any guy and anchor (see photo 8).

Photo 8

Photo 9

Furthermore, the majority of the system sample that we observed contained improperly applied guys and anchors (see photo 9).

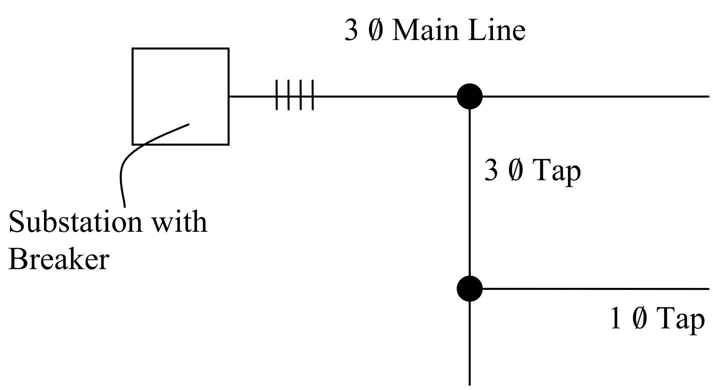
In some areas, guy leads were not long enough and were not placed on the pole at the proper attachment location to adequately support the pole. There also seems to be a systemic problem with guys that were not grounded which can create a touch potential. It is a practice that is discouraged and needs to be changed.

All guys should be grounded to the system neutral. Many poles were leaning due to the conductor loading and misapplication of guys. Also, poles were found undersized or under-classed for the amount of telecommunications and power on the pole. We recommend make-ready work to identify these locations. We did not identify these as corrective actions necessary immediately but clearly this is a problem that needs to be dealt with in the near future. Guys and anchors should be applied to provide for proper transverse loading support as required by the NESC and as is customary utility practice. The design and construction and material <u>shall</u> comply with the NESC. JCP&L will need to design and inspect their construction in order to comply

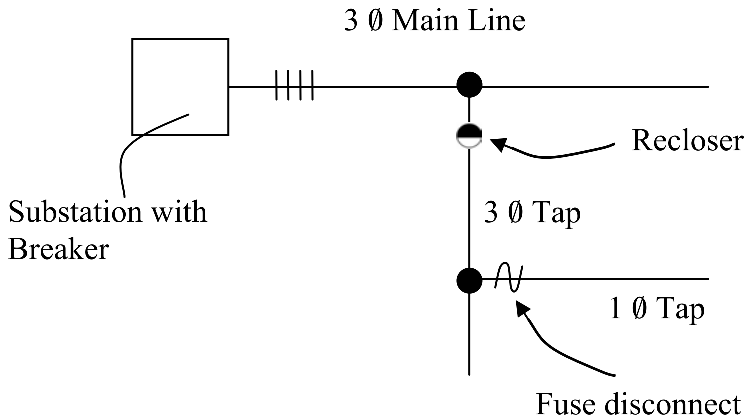
Paragraph 15 of the MOU addresses and resolves concerns related to joint pole use with telecommunications companies. Further, the Stipulation of Settlement entered into on June 8, 2004 by JCP&L and Board Staff (and which was presented to, and adopted by, the Board), resolves the remainder of this concern.

We understand that JCP&L has a program that addresses sectionalizing, fuse coordination and related issues. However, in general observation we noted a number of areas where a three-phase line was tapped off an exiting three-phase line. Then a single-phase line was tapped off of the three-phase line and went further into a residential area with no fuse disconnects, switches, or reclosers. This is clearly a problem that adds to the duration of an outage and the number of people affected by the outage. We recommend that the system coordination review be expedited.

The following one-line sketch is an example of what was observed versus what should be established by JCP&L through its Accelerated Reliability Initiative. Increased sectionalizing will reduce the number of customers outaged and the duration of the outage. The present JCP&L plan is simply a start at a system-wide protective coordination program.



As Found



As Proposed

Paragraph 4 of the MOU and, to the extent that JCP&L agrees to fully comply with its Asset Management Strategy (AMS) document including the CRI program, which agreement is reflected in the Stipulation of Settlement (which includes the published AMS to which JCP&L has agreed to abide) entered into on June 8, 2004 by JCP&L and Board Staff (and which was reviewed and adopted by the Board), resolves the remainder of this concern.

The general observations of the system by our Engineers and Technicians combined with the information from interviews and employee comments reflect a lack of commitment by JCP&L to adequate operations and maintenance of the electric distribution system poles and wires and associated equipment. These can generally be described by the following four areas or themes:

1. There are deficiencies in the design process, including insufficient engineering and inspections associated with line construction.

2. Spend only what is minimally required to keep the system operating.

3. Management offers a good training program; however, virtually no one participates in the program and JCP&L does not instill pride in workmanship.

4. An independent construction inspection program to assure compliance with JCP&L published standards, good utility practice and the NESC is not a part of JCP&L practices.

The following observations support a general theme of underfunding for maintenance:

1. There are numerous instances observed that when a broken pole was encountered, it was corrected with a temporary, not a permanent, fix and left in that condition indefinitely with no plans to remedy the defect.. There is no evidence of poles being replaced unless they are broken and unrepairable.

2. When new poles are installed, there are instances when the old pole is not removed and some equipment is left attached while only the conductors are moved to the new pole.

3. Capacitor banks were found to be destroyed. Rather than removing the capacitors, they were simply disconnected and a replacement bank installed on an adjacent pole.

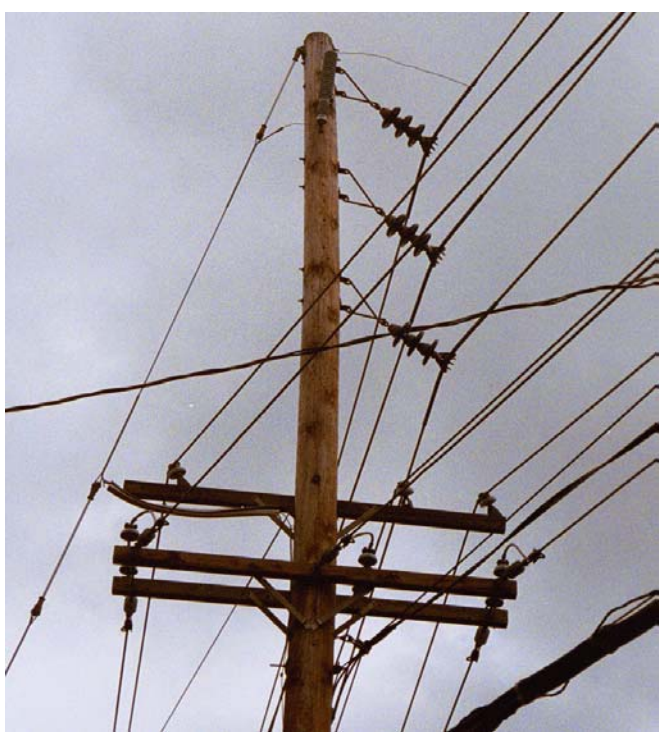
4. Pole-top extensions are used in certain locations rather than resizing and installing new poles to meet the NESC.

5. Poles marked for removal by Osmose are still in service. The 2002 Central New Jersey work plan called for the removal of double red-tagged poles only.

The following observations support both lack of training and lack of pride in workmanship of the crews and lack of engineering and inspection:

1. There were instances where guy wires were used to ground the surge arresters installed on the top phase (see photo 10).

Photo 10



2. When poles are close to curbs, ground wires have been installed on the curb side and in most instances, snowplows have cut these grounds. Installing the grounds on the opposite side of the pole would have prevented what is now a serious problem of inadequate grounding on the system.

3. Some transformers are in danger of falling because their mounting brackets were installed incorrectly or not bolted tightly.

4. Pole-top transformer improperly mounted with the bushing higher than the primary conductor.

5. An open wire secondary rubbing the tank of a transformer was repaired by installing an insulating blanket to insulate the secondary.

6. JCP&L construction crews do not use sag and tension charts for the installation of most overhead conductors.

The following observations show a general lack of good engineering practice in Design and Construction:

1. JCP&L construction standards have not been used for guying their angle and dead-end structures. Most guy leads are too short. Not all locations that need guying are guyed. Inadequate number of guys and anchors is prevalent.

2. Push pole bracing observed was installed too high on the pole. This causes the pole to deflect at the top and the brace pole to bow in the center.

3. Guys are not grounded and guy strain insulators are not consistently used in guys.

4. Pole loading on joint-use poles is excessive, and engineering analysis is clearly not being performed prior to attachment of CATV and telephone cables (see photos 11 and 12).

Photo 11

Photo 12

5. A major problem observed on almost all circuits was the inadequate use of circuit sectionalizing to protect lines from faults. Circuit feeders are unprotected all the way back to the substation. Not all primary taps are fused. Use of recloser banks was practically nonexistent.

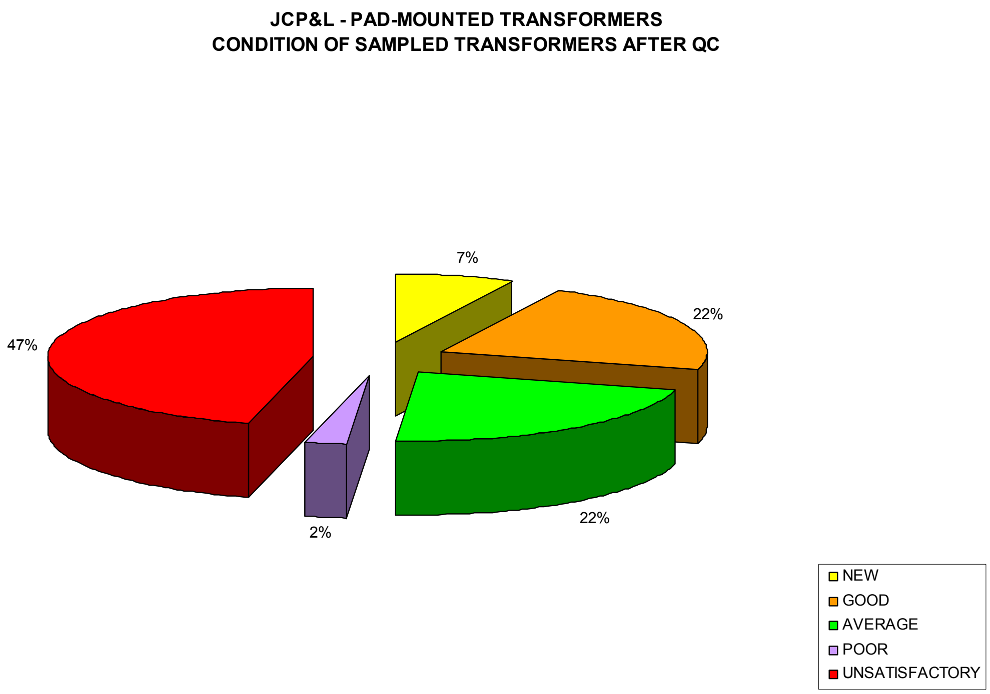
6. One design philosophy of JCP&L that seemed questionable was their use of extremely long secondary spans. Spans have a three (3) -wire service underbuild whether it is needed or not, and the lengths back to the transformer would be on average around 500 feet. In some areas, the secondary length might be as long as one thousand (1,000) feet. This design method causes problems with voltage drop. Accompanied with JCP&L's tendency to connect too many houses to a transformer, overloading at transformers is common.

7. JCP&L has no program for lines to be staked or designed by trained technicians or engineers. JCP&L uses no staking manual to assure proper design.

Distribution Pad-Mount Transformers

JCP&L has over 46,000 pad-mounted transformers in service. A total of 507 pad-mounts were inspected during our condition assessment. These transformers were spread over twenty-six (26) circuits distributed equally in both the Northern and Central Regions. *Figure 7* below shows the condition of the sampled pad-mount transformers in the Northern Region.

Figure 7



Forty-seven percent (47%) of the sampled pad-mounts were observed to be unsatisfactory. Two percent (2%) of the pad-mounts were rated as poor.

Appendix E contains our Engineers' written evaluation of the pad-mount inspections conducted during our condition assessment. Also included are photographs and summary discussions from all locations rated as unsatisfactory or poor. A cost estimate projecting the total material and labor costs required to repair or replace facilities observed to be in unsatisfactory or poor condition is included.

The majority of the pad-mounts did not have pentahead bolts; this is an NESC Code violation and creates an extreme safety problem. In some cases, vegetation management is a problem. Shrubbery planted by the transformers can cause safety problems for the employees and make the transformers difficult to find and open. In many locations landscaping has partially buried pad-mount transformers. This is an unacceptable operating condition.

Of the 507 locations inspected, 234 items were identified as "unsatisfactory." The corrective actions were separated into 6 groups and identified as follows:

(1) *Vegetation, Excavation and Labor*. Shrubbery and bushes around a transformer would fall under *vegetation* where access was blocked or there was a safety issue for the employee trying to work around it. The vegetation removal is associated primarily with plants in front of the access cover or door. This vegetation restricts access and precludes workers' ability to comply with NESC work rules and OSHA standards as related to approach distance to the transformer, particularly energized. *Excavation* was needed if the transformers had dirt and debris around them making it difficult to open. This condition also leads to premature rust. *Labor* and *Work Rule* were observed by Booth and included the fiber boards on live front transformers had been removed. This is a National Electrical Safety Code violation. The cost to correct this was estimated to be similar to that of vegetation removal or excavation.

(2) Replacement of a transformer was recommended if significant rust, significant oil leaks or public safety issues were identified.

(3) Elevation. A number of transformers were found to be below grade. One transformer was found to be halfway below grade and it was an above-ground transformer. (See Photo 13)

Photo 13

(4) Termination. A few transformers had elbows that appeared to show signs of early electrical breakdown. Our recommendation was to replace and re-terminate the elbow only.

(5) Pentahead Bolts. Pentahead bolt removal was a significant problem. Apparently, there is a system practice to remove pentahead bolts from a transformer to create ease of access for the construction workers. This creates the same ease of access for the public. This is clearly an NESC violation as well as a major safety problem that needs to be dealt with immediately. Approximately 40% of the transformers that were inspected did not have pentahead bolts.

(6) Lightning Arresters. A number of pad-mounted transformers at open points did not have lightning arresters. In addition, some radial transformers did not have lightning arresters. Application of lightning arresters at these locations has been found by the industry to improve reliability and increase equipment life.

Reliability. Reliability was divided into two components: the potential to cause an outage and the potential to prolong the outage.

Safety Issues. Safety issues were identified as those where the employee or the public were at risk and those that could contribute to the duration of an outage. Our estimate to replace or repair the items observed on a prorated basis across the system would be $11,646,320. See Table 3, Appendix E.

Paragraph 3 of the MOU addresses these pad-mounted transformer concerns. And to the extent not addressed by paragraph 3 of the MOU, these issues are addressed and resolved by the Stipulation of Settlement dated June 8, 2004.

JCP&L has 9,543.85 miles of underground cable located in the following counties:

Table 10
Underground Cable

Location	Miles
UNDERGOUND DISTRIBUTION	
Burlington County	116.69
Essex County	54.46
Hunterdon County	837.13
Mercer County	200.52
Middlesex County	641.21
Monmouth County	2,199.71
Morris County	1,760.14
Ocean County	2,200.80
Passaic County	61.23
Somerset County	660.34
Sussex County	338.07
Union County	97.76
Warren County	375.79
Total Underground Distribution:	9,543.85

Underground service reliability is being impacted by JCP&L Design and Maintenance Practices. New subdivisions that have forty (40) or fewer residential customers use a radial feed, not a loop system. This practice should be modified immediately. Linemen have cited two work practices which, if prevalent, are contributing to extended outages in underground service areas:

1. Apparently, underground burnouts on an existing loop system are not repaired. This means the loop system is eliminated. This practice will substantially increase the number of miles of radial underground system. This is not prudent or customary utility practice. The effect of this policy is the creation of mostly radial feeds. Repairs to the damaged feeder are made only when the feeder fails again. This means much longer outage location time, longer repair time and much more expensive outage restoration cost since the cables are repaired often during overtime pay hours without pre-planned materials and requiring many unproductive work hours.

2. GPU, as a result of a technical recommendation in the Order in Docket No. EX99100763, had a program designed to replace old underground primary lines that had the exposed concentric neutral. The neutrals deteriorated because of earth conditions. JCP&L has apparently eliminated this replacement program. Our inspection teams were unable to verify the extent of this potential problem. However, if there still exists extensive exposed concentric neutral cable in areas of JCP&L's service territory, a new testing and replacement program should be re-established, especially in Monmouth, Ocean, and Morris Counties, where the majority of the underground cable is located.

It is widely known in the industry that high-molecular-weight polyethylene and cross-link polyethylene bare concentric neutral cables begin to experience neutral failure near the end of their estimated thirty (30) -year life due to electrolysis. If water and gas lines are installed close to the cable, this contributes further to the electrolysis problems. There is available state-of-the-art cable-fault-locating equipment that can be incorporated into an effective preventive maintenance program which will allow the location of cable splices in need of repair prior to outages occurring.

The underground issues and recommendations have been addressed and resolved by the Stipulation of Settlement dated June 8, 2004 by and between JCP&L and Board Staff.

3. Capital Improvements Review

Capital Expenditures

Historical Capital Expenditures for the JCP&L system over the 1998 to 2002 period are shown below in Table 11:

Table 11
Distribution Capital Expenditures
1998-2002

Region	1998	1999	2000	2001	2002
NJ – Northern	[1]	$57 million	$66 million	$73 million	$38 million
NJ – Central	[1]	54 million	78 million	79 million	56 million
Total	$109 million	$111 million	$144 million	$152 million	$94 million

[1] Separation by Region not available

Additional Comments:

- *Excludes Genco/Nuclear*
- *Excludes Support including Fleet & IT*

The increases in 2000 and 2001 reflect an acceleration of capital spending by an extra $56 million above normal spending in response to the Phase II Board Order addressing the July 1999 heat wave outages. The reduction in 2002 was the result of the merger integration review using new planning criteria by First Energy that resulted in a number of projects being removed from JCP&L's 2002 capital plan.

The T&D Capital Expenditures Forecast for 2003 is $102 million, and $120 million annually for 2004 through 2007. With total T&D expenditures projected at $120 million annually through 2007, FE has reduced capital spending approximately 15% compared to the pre-merger GPU JCP&L Expenditures as reported by Stone & Webster and shown below in Table 12:

Table 12
Transmission & Distribution Capital Expenditures

	1995	1996	1997	1998
Transmission	$ 18 million	$ 19 million	$ 15 million	$ 9 million
Distribution	120 million	116 million	125 million	109 million
Total	$138 million	$135 million	$140 million	$118 million

The nine (9) -year average distribution capital expenditure has been $108 million. Given the results of our condition assessment, this level of spending has not been sufficient to maintain facilities in an acceptable condition to prevent degradation of system reliability. Table 13 below shows a breakout of capital expenditures by work type:

Table 13
Distribution Capital Expenditure Details
1998-2002

Type	1998	1999	2000	2001	2002
New Business	$48 million	$51 million	$45 million	$41 million	$36 million
System Reinforcement	20	32	77	96	41
Relocation, Replacements	31	22	17	11	15
Other	10	6	5	4	2
Total	$109 million	$111 million	$144 million	$152 million	$94 million

Based on a five–year average, new business represents thirty-six percent (36%) of annual Capital Expenditures for the JCP&L Distribution System. System Reinforcement will equal forty-four percent (44%), and Relocations and Replacements has been sixteen percent (16%).

Figure 8
Capital Budgets FirstEnergy Operating Utilities
($ millions)

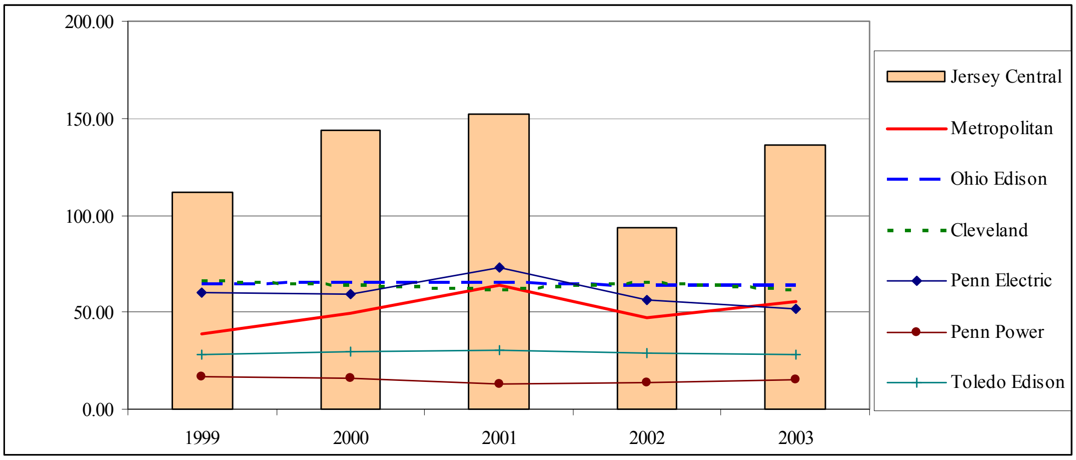


Figure 8 above shows a comparison of the JCP&L capital budgets for a five-year period compared to the capital expenditures of the six other FirstEnergy operating utilities. It must be realized that there is an approximate 24% difference in cost of electrical construction between Ohio and New Jersey; this accounts for a significant part of the higher JCP&L capital expenditures.

The current Capital budgeting procedure for JCP&L is similar to the procedures used by GPU, Inc. Under the GPU procedures, the Comptroller's function of each operating utility was responsible for developing annual budgets; the Board of Directors and subsidiary Boards were responsible for reviewing and approving annual budgets. Budget approval represented an annual spending limit and not approval of specific projects.

Any project in excess of $2.5 million required subsidiary Board approval; projects between $10 million and $25 million were subject to approval by the Finance Committee; and projects in excess of $25 million had to be approved by the Board of Directors subject to the recommendation of the Finance Committee. Approved Annual Budgets were maximum limits. In the event that funds are not provided in the budget for a project which management had subsequently determined should be undertaken, or if a project overrun was not avoidable, one or more budgeted projects or other non-project work might need to be canceled, deferred to a future period, or otherwise reduced in cost in order to remain within the overall budget levels.

Information provided by JCP&L on February 19, 2004 included the *FirstEnergy Corp. Summary Guidance to Budgeting Capital Expenditures,* which

JCP&L indicated now applies in New Jersey. Under these guidelines, value centers are identified with Table 14 showing the Vice President's Approval Thresholds:

Table 14

FirstEnergy Corp. Summary Guidance to Budgeting Capital Expenditures Vice President's Approval Thresholds				
		Individual Projects		**Projects in Aggregate**
Energy Delivery Distribution Transmission		 $ 500,000 $ 500,000		 $ 15,000,000 $ 5,000,000
Fossil Production		$ 500,000		$ 10,000,000
Nuclear Production		$ 500,000		$ 10,000,000

Individual projects and aggregated blanket projects submitted and approved by Value Center Heads are submitted to a Capital Review Committee. The Capital Review Committee sets the tentative capital budget. A senior management committee reviews the tentative capital budget and makes recommendations. The FirstEnergy CEO approves the Final Capital Budget. If changes to the capital expenditures initially submitted by the individual value centers are required, senior management works with the various value centers to re-evaluate projects and make final revisions to their capital expenditure plans.

In 2002, cash flows provided from operating activities totaled $309 million for JCP&L, compared to $289 million in 2001. Cash requirements in 2003 for operating expenses, construction expenditures, scheduled debt maturities and preferred stock redemptions are expected to be met without increasing net debt and preferred stock outstanding. Over the next three (3) years, JCP&L, according to its 2002 10K statement, expects to meet contractual obligations with cash from operations.

FirstEnergy is the sole holder of JCP&L's common stock and the common stock of the other Ohio and Pennsylvania operating companies. In 2002 FirstEnergy received $447 million in cash dividends on common stock from its subsidiaries. FirstEnergy decisions which impact its operating utilities' ability to pay dividends can be in direct conflict with decisions related to capital additions and maintenance expenditures needed to maintain and improve the utility's infrastructure.

Our review of the potential sources of financing available to JCP&L far exceeds its current capital expenditures forecast. The 2002 Form 10K listed the following sources for future cash requirements in addition to funds to be received from operations:

Table 15
Potential Sources of Capital

Source	Limit
Cash and Temporary Investments	$ 5 million
1st mortgage bonds against previously retired bonds	393 million
Preferred stock	1.2 billion [1]

[1] *Based on earnings for 2002, an assumed dividend rate of 9%, and no additional indebtedness.*

A constant theme espoused during our Audit interviews was the autonomy each Regional President held to operate the Region. Based upon our review of the actual Capital budgeting process, the Regional Presidents have very little autonomy to control the needed capital expenditures to upgrade the JCP&L infrastructure. The real authority lies with the First Energy Board of Directors. Regional managers and executives develop projects to fill a mandated maximum budget level.

Based on JCP&L's responses to Data Requests No. 22 and staff's follow-up Data Request No. 22A, JCP&L appears to have no written procedures to notify the Audit Committee of the Board's ordered Audits. It also appears that the Board of Directors may have not been notified of the Audit or at least not in a timely manner. FirstEnergy filed no 8-K Report with the Securities and Exchange Commission to report the Focused Audit of JCP&L as a material event that is of importance to investors.

Effective January 5, 2004, FirstEnergy appears to have shifted from its regional concept of governance to a subsidiary-based approach. Stephen Morgan was named president of the Company's Jersey Central Power & Light subsidiary. Reporting to him will be Donald Lynch, Regional President of Central New Jersey Region, and Steven Strah, Regional President of Northern New Jersey Region. It is our recommendation that the New Jersey Board of Public Utilities authorize a governance audit of JCP&L.

As indicated in the Executive Summary, Booth & Associates, together with Board Staff and the Company engaged in an iterative process which made significant progress towards addressing all recommendations and, insofar as the issues discussed above are concerned, the Stipulation of Settlement entered into on June 8, 2004 by and between JCP&L and Board Staff (and which was presented to and adopted by the Board), resolves any issues, concerns and/or recommendations about the matters addressed in this Section of our report.

4. Project Prioritization

Transmission versus Distribution

Since 1998, JCP&L has only installed 7.2 miles of 230 kV line as additions to its transmission system. There appears to be no prioritization between Distribution and Transmission at the planning level. Prioritization is undertaken within each function. Under the PJM Regional Transmission Expansion Planning (RTEP) Process, the system is modeled each year and a comprehensive load flow analysis conducted to determine the ability of the PJM system to meet the single contingency, second contingency, and multiple facility outage contingency tests required of the MAAC Reliability Principles and Standards. The system is also analyzed for its ability to meet power transfer requirements of the MAAC criteria and to determine compliance with stability requirements. The baseline plan is modified as a result of generation being added or removed from the system to produce the RTEP. The RTEP is presented to the PJM Board of Directors for approval. PJM Transmission owners may elect to build additional system reinforcements not identified as required through the RTEP analysis. Transmission owners construct, own and finance the transmission facility enhancements or expansions specified in the RTEP based upon assignment of cost responsibility included in the plan.

Prioritization of Distribution Projects

The Engineers interviewed prioritized distribution projects included in the Capital Budget in the following order:

1. Safety – projects receive the highest priority that eliminate hazards to employees and the public.

2. Need – forced work required to meet load growth.

3. Reliability-related – commitments made to customers and regulatory agencies. Within this priority, reliability projects that reduce frequency of outages are ranked highest. Note: The planners **do not** use data from the Outage Management System, PowerOn, Crew Work Process, including meeting input.

New business meetings are held in each region monthly. The need date of a project is the driver of the priority assignment for new business.

The Regional Directors of Operations and Operations Support classified work for their crews into three areas:

1. Accelerated – simple jobs requiring no support.
2. Planning – required assistance of layout technician at shop.
3. Engineering – major work requiring corporate engineering.

Prioritization of this work varied by Director. One Director of Operations Support prioritized work orders as follows:

1. Hazard
2. Reliability
3. Capital projects
4. Preventive maintenance.

The Directors of Operations prioritized work orders for their line crews based on a different ranking of criteria:

1. Customer in-service date
2. Equipment maintenance
3. Reliability projects.

Line contractors are assigned reliability projects including the Accelerated Reliability Improvement Plan and large T&D projects. Other work is performed by specialized contractors including vegetation management, ducted manholes, directional boring and flagging and locations.

Project priorities presently used by JCP&L are different from those reported by Stone & Webster as being used by GPU Energy. Under the GPU budget process, project priorities included:

Forced work:	New Customers Storm Repairs Relocations
Non-forced work:	Reliability Environmental Safety

The CREWS module utilized by FirstEnergy to prepare all work orders has a field that can be used to prioritize the work order. This function is not being used at the current time.

During our interviews, the Directors of the various departments indicated that benchmarks and goals are set; however, each Region is responsible for figuring out how to repair the system to achieve goals. In addition, the Directors considered the budgeting process and prioritization of work a fluid process.

Given JCP&L's current reliability problems, work prioritization is not a significant issue. As shown below in Table 16, response to outages represents the majority of the work orders completed by the Operations Services Departments in both Regions:

Table 16
Work Orders Completed and Back log
2002

Category	*Completed*	*Carryover*	*Total*
CNJ			
Maintenance	1,351	373	1,724
New Construction	216	34	250
New Service	5,757	640	6,397
Outages	36,743	8,261	45,004
Total CNJ	44,067	9,308	53,375
NNJ			
Maintenance	3,810	481	4,291
New Construction	721	90	811
New Service	3,650	250	3,900
Outages	28,423	5,837	34,260
Total NNJ	36,604	6,658	43,262

As indicated in the Executive Summary, Booth & Associates, together with Board Staff and the Company engaged in an iterative process which made significant progress towards addressing all recommendations and, insofar as the issues discussed above are concerned, the Stipulation of Settlement entered into on June 8, 2004 by and between JCP&L and Board Staff (and which was presented to and adopted by the Board), resolves any issues, concerns and/or recommendations about the matters addressed in this Section of our report.

5. Load Forecasting

The load forecast methodology used for forecasting JCP&L peak loads and energy is the same used by GPU, Inc. prior to the merger; however, the use of the sensitivity studies for planning purposes has changed. Multiple models are maintained including multiple regression, exponential smoothly and Box-Jenkins. A single model is applied for each year in a ten-year forecast horizon. An econometric model in Forecast Pro created for GPU by Business Forecast Systems is always the starting point used to forecast kWh sales. The Peak demand forecast is developed using internal regression models. In our opinion, the load forecasting methods reflect standards in terms of data, economic and demographic variables used, and types of modeling used.

The Peak load forecasts are used for both internal JCP&L planning and PJM reporting requirements. Monthly summer and winter peaks for a ten-year period are issued to the T&D function in Reading, which allocates the total system peak to Region, then to substation areas. Sensitivity studies of 90/10, 50/50, and 10/90 (percent probabilities of being too high or too low) are developed. The 50/50 case is submitted to the PJM Load Analysis Subcommittee and used to develop the Annual PJM Load Forecast Report. Section 8 deals with the distribution load forecasting in detail. Table 17 below shows actual and forecast Peak Demand and Annual Energy for the period 1998-2007.

Table 17
JCP&L Actual Load vs. Forecast

	Peak MW	Annual GWh
1998	4,817	21,613
1999	5,300	22,451
2000	4,961	21,031
2001	5,592	22,884
2002	5,820	23,008
2003	*5,980*	*22,988*
2004	*6,147*	*23,455*
2005	*6,295*	*23,916*
2006	*6,446*	*24,378*
2007	*6,588*	*24,852*

JCP&L is a sub-zone of the PJM East area. Monthly Peak and Energy Forecasts are shown in Table 18 for the next three years.

Table 18
Peak and Energy Forecast for JCP&L

	2003		2004		2005	
	Peak MW	Annual GWh	Peak MW	Annual GWh	Peak MW	Annual GWh
Jan	3,727	1,997	3,773	2,037	3,845	2,077
Feb	3,501	1,737	3,544	1,771	3,611	1,805
Mar	3,318	1,813	3,359	1,848	3,422	1,883
Apr	3,263	1,601	3,304	1,633	3,366	1,664
May	4,171	1,719	4,286	1,754	4,389	1,788
Jun	5,388	2,106	5,537	2,149	5,670	2,192
Jul	5,980	2,355	6,147	2,405	6,295	2,454
Aug	5,413	2,363	5,562	2,413	5,696	2,462
Sep	4,593	1,881	4,720	1,920	4,833	1,959
Oct	3,213	1,721	3,273	1,756	3,324	1,790
Nov	3,369	1,720	3,433	1,754	3,486	1,788
Dec	3,648	1,975	3,716	2,015	3,773	2,054
		22,988		23,455		23,916

Schedule 4.1 of the PJM Reliability Assurance Agreement specifies the following formula to be used for determination of the forecast pool requirement of PJM regions:

$$ICR = (FAP – FALC)*(1 + IRM)$$

Where:

ICR = installed capacity requirement

FAP = the forecast accounting peak for the PJM Region, which shall be the weather-normalized 50/50 probability load prior to active load management being involved.

FALC = the forecast of the active load management credit adjustment for the PJM region

IRM = the installed reserve margin approved by the Reliability Committee for the Planning Region, currently 16%.

Every Load-Serving Entity within the MAAC Control Zone shall be responsible for satisfying the Forecast Pool Requirement related to the end uses it serves.

New Jersey implemented retail choice in August of 1998, adopting a four-year transition period. During the first three years (August 1, 1999-July 31, 2002), the four New Jersey Electric Distribution Companies (EDCs) supplied the customers who did not switch to a competitive retailer. In the fourth year (August 1, 2002 through July 31, 2003), the EDCs jointly proposed an auction in which suppliers competed to provide basic generation service (BGS). In February 2002 and again in February 2003, statewide auctions were held to procure electric supply to serve the Basic Generation Service load of the four (4) EDCs. In the February 2002 auction, JCP&L's BGS Peak load share was 5,146 MW, which was sold in fifty-one (51) 100-MW blocks called "tranches" to the following Bidders for a final auction price of 4.865¢/kWh:

1. Ameradon Hess Corp. (1)
2. Aquila Energy Marketing Corp. (5)
3. Consolidated Edison Energy Inc. (3)
4. Duke Energy Trading and Marketing (5)
5. First Energy Solutions Corp. (2)
6. Select Energy Inc. (15)
7. Sempra Energy Trading Corp. (9)
8. TXU Energy Trading (3)
9. Williams Energy Marketing & Trading Co. (8)

These winners were responsible for fulfilling all the requirements of a PJM Load Serving Entity (LSE) including capacity, energy, ancillary services, transmission, and any other service as may be required by PJM.

The February 2003 auction involved two (2) auctions: first, the BGS-HEP auction for Basic Generation Service to Commercial and Industrial Electric Pricing (CIEP) customers for an hourly electric price (HEP); and second, the BGS-FP Auction for basic generation service for fixed price (FP) to smaller commercial and residential customers. In the BGS-HEP Auction, JCP&L's Peak load share of 923.2 MW was sold in thirty-seven (37) 25-MW tranches to the following winning bidders:

1. Constellation Power Source, Inc. (4)
2. Dominion Retail, Inc. (14)

3. First Energy Solutions (3)
4. Morgan Stanley Capital Group, Inc. (1)
5. PPL Energy Plus, LLL (15)

In the February 2003 BGS-FP auction, JCP&L's peak load share of 4,360.7 MW was sold in thirty (30) 10-month tranches and fourteen (14) 34-month tranches to the following suppliers:

1. Conectiv Energy Supply, Inc. (5; 5)
2. Constellation Power Source, Inc. (1; 0)
3. First Energy Solutions (0; 3)
4. J. Aron & Company (7; 0)
5. PPL Energy Plus, LLC (0; 5)
6. Reliant Energy Services, Inc. (7; 0)
7. Select Energy, Inc. (0; 1)
8. Tractebel Energy Marketing, Inc. (10; 0)

For the period starting June 1, 2004, a February 2004 auction will be held separately but concurrently for the EDCs' BGS-FP load and BGS –CIEP load. Since one-third (1/3) of the EDCs' load has already been procured in an auction held in February 2003 and has a 24-month term remaining, two-thirds (2/3) of the EDC load will be procured through the February 2004 BGS-FP auction. One-half (1/2) will be procured for a one-year term (June 1, 2004 to May 31, 2005) and the remaining one-half procured for a period of three years (June 1, 2004 to May 31, 2007).

The end result of this Auction will be that on June 1, 2005, the EDCs will have under contract approximately one-third of their total BGS Load with a remaining contract term of one year, approximately one-third of their total BGS Load with a remaining contract term of two years, and would need to procure approximately one-third of their total BGS Load for a term of three years starting June 1, 2003 in order to maintain this term averaging.

Table 19 below summarizes the load to be procured by JCP&L:

Table 19
BGS-FP Number and MW-Measure of Tranches

Number of Tranches								
	FP Peak Load Share (MW)	Procured in 2003 (2-year term remaining)	To Be Procured in 2004		Load Caps		Size of tranche (%)	MW-Measure
			1-year	3-year	1-year	3-year		
JCP&L[i]	5089.3	14	12	15	4	5	2.27	115.67

[i] *As a pilot program, three tranches of BGS-FP Load that would otherwise have been included in JCP&L's one-year BGS-FP Auction (covering the period from June 1, 2004 to May 31, 2005) will be withheld from that Auction to be served by JCP&L. The FP Peak Load Share, total tranches and calculation of the MW-measure include the tranches served by JCP&L.*

The February 2004 BGS-CIEP auction will procure full requirements of the commercial and industrial load for a one-year term from June 1, 2004 to May 31, 2005. For JCP&L, 700.7 MW of CIEP peak load will be procured in 28 tranches of 25.03 MW each.

JCP&L has developed a Contingency Plan to address three possible occurrences:

1. JCP&L receives an insufficient number of bids to provide for a fully subscribed auction volume, either for the BGS-FP auction or the BGS-CIEP auction.

2. A default by one of the winning bidders prior to June 1, 2004.

3. A default during the June 1, 2004-May 31, 2007 supply period.

JCP&L has an existing fiscal or financial entitlement in approximately 1,200 MW of generation, including non-utility Generation Contracts, restructured replacement power contracts, customer generation under the operation of JCP&L and generation assets owned by JCP&L including Yards Creek and Forked River. Except where retained to meet requirements of the Contingency Plan, JCP&L will continue to sell all of the energy, capacity and ancillary services associated with its committed supply into the PJM Spot Market. In the event there are insufficient number of bids in Auction, JCP&L's Contingency Plan calls for JCP&L at its option to purchase necessary services through PJM-administered markets or retain its committed supply to serve tranches not obtained in the auction. If a winning bidder defaults after the auction but prior to service beginning, JCP&L plans at its option to offer the tranches under default to other winning bidders in the auction, procure generation in PJM-administered markets or retain its committed supply to serve the defaulted tranches. If default occurs during the June 1, 2004 through May 31, 2007 supply period, at JCP&L's option the defaulted tranches will be offered to other winning bidders, procured in PJM-administered markets or JCP&L's committed supply retained to serve the defaulted tranches.

Part of the scope of work for this load forecasting section was to determine if adequate resources are or have been allocated to accommodate the projected growth. As can be seen from the discussion above, strong markets exist in PJM for generation supply in a deregulated environment. JCP&L, with its retained capacity of approximately 1,200 MW and these strong markets which exist in PJM, provide adequate generation resources to accommodate JCP&L's projected growth. Purchasers of JCP&L's Basic Generation Service in New Jersey auctions must meet all PJM requirements as a Load Serving Entity. The projected generation reserves based on resources committed to meet load for the 2004 summer period is 18.9%. Therefore, there are good assurances that future load in New Jersey can be met by generation.

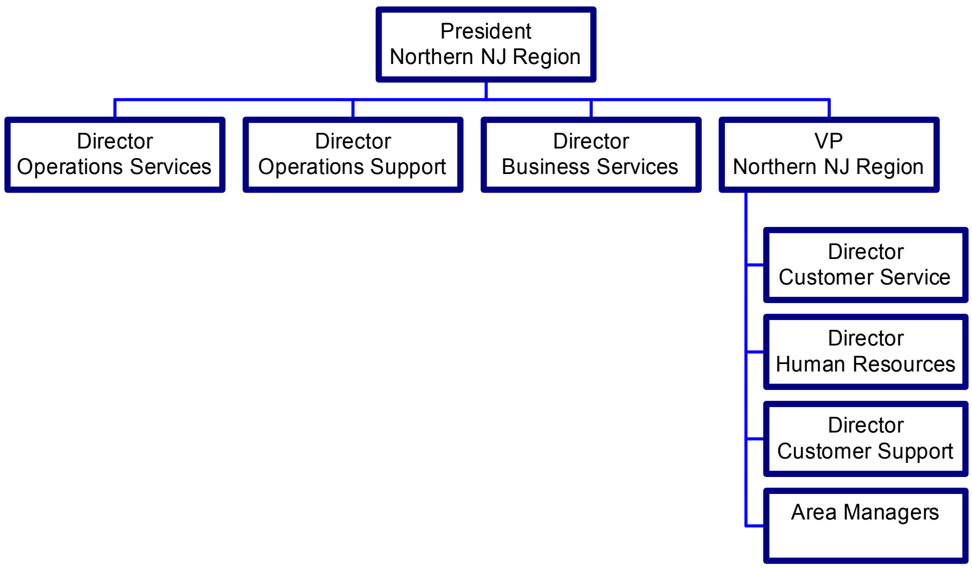
As indicated in the Executive Summary, Booth & Associates, together with Board Staff and the Company engaged in an iterative process which made significant progress towards addressing all recommendations and, insofar as the issues discussed above are concerned, the Stipulation of Settlement entered into on June 8, 2004 by and between JCP&L and Board Staff (and which was presented to and adopted by the Board), resolves any issues, concerns and/or recommendations about the matters addressed in this Section of our report.

6. Organization and Staff

Organization

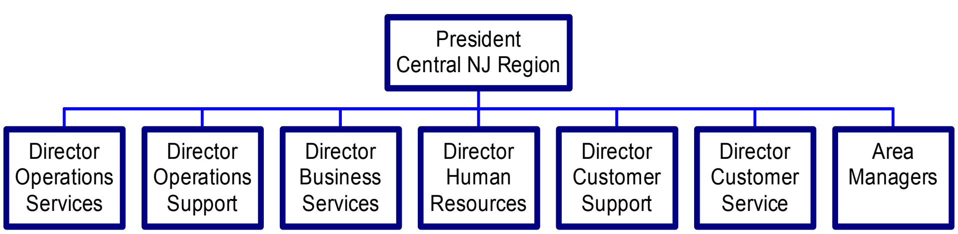
Following the FirstEnergy/GPU, Inc. merger, a decentralized organization model was adopted companywide. Seven (7) operating companies have been organized into nine (9) operating regions. Operating regions are managed locally. The Northern New Jersey Region organization is shown below in Figure 9:

Figure 9
Northern New Jersey Region Organization



The structure for the Central New Jersey Region is similar except there is no Region VP in the Central Region. The Directors of Customer Services, Human Resources and Customer Support, and the Area Managers report directly to the President Central NJ Region as shown below in Figure 10:

Figure 10
Central New Jersey Region Organization



The FE/GPU merger was announced in August 2000 and finalized on November 7, 2001. Responsibility for the merger integration resided with twelve (12) teams that touched all areas of operations. T&D O&M practices were addressed by a Core Team composed of five (5) GPU and five (5) FE technical employees. Primary goals listed by the Director of Energy Delivery, Technical Services, who had overall responsibility for the integration, included:

- Cost reduction
- Reliability improvement
- Improvement in vegetation management program
- Improvement in work practices
- Standardization of Design and Construction specifications for all FirstEnergy Operating Utilities

Senior executives at FirstEnergy were aware of the perceived and/or real reliability-related problems at JCP&L at the time of the merger. Details of reliability improvement were not addressed during the merger integration by the Core Teams.

A result, although not a stated goal, of the merger was a 1:1 ratio of pre-merger JCP&L management personnel to pre-merger FE management personnel in JCP&L's final management team.

JCP&L provided the following descriptions of the primary responsibilities for the management positions within the organization:

Regional President

Responsibilities include the executive management of the overall planning and execution of major work processes within one of the company's operating regions that provides electric service to customers, including distribution engineering, construction, operations, and maintenance; customer services, which includes regional customer accounting, meter reading and credit/collections; customer support, which includes management of special contracts and consulting services for all customer classes; and community relations, which involves creating and maintaining relationships with community leaders such as elected officials, key business leaders, non-profit organizations and educators. This position is also responsible for support functions within the Region such as human resources, employee safety, and all aspects of the Region's financial management. This position oversees a professional staff and physical workforce and ensures that all activities within the Region are performed in compliance with FirstEnergy corporate policy, all local, state, and federal laws, and all state and federal regulations related to electric distribution operating companies.

Regional Vice President
Responsibilities include planning and execution of customer service processes and community relations within one of the company's operating regions that provides electric service to customers, including regional customer accounting, meter reading, and credit/collections; customer support, which includes management of special contracts and consulting services for all customer classes; community and local governmental relations including creating and maintaining relationships with community leaders such as elected officials, key business leaders, non-profit organizations and educators and oversight of the preparation of community-contact programs designed to exchange information with residents, and elected officials, and promote goodwill. This position is also responsible for internal support functions, including human resources and employee safety.

Director, Operations Services
Responsibilities include planning and execution of distribution engineering, construction, operations and maintenance of the electric distribution, subtransmission, and transmission facilities within one of the company's operating regions that provides electric service to customers. Functional responsibilities include lines, vegetation management, dispatching, engineering, and claims. Promotes a safe work environment.

Director, Operations Support Services
Responsibilities include planning and execution of distribution engineering, construction, operations and maintenance of the electric distribution, subtransmission, and transmission electric facilities within one of the company's operating regions that provides electric service to customers. Functional responsibilities include substation, meter services, underground network, fleet services, and materials warehousing. Promotes a safe work environment.

Director, Regional Business Services
Responsibilities include financial oversight for one of the company's operating regions that provides electric service to customers which includes planning, development, management, and reporting of a combined capital and O&M budget, financial analysis and performance monitoring. Also coordinates major outage reporting, performs billing and collection of customer claims, and coordinates special projects as needed.

Director, Regional Human Resources
Responsibilities include administration of human resources and employee relations programs in accordance with established FirstEnergy policies and procedures, compliance with local, state, and federal laws, and state and federal regulations related to employment, human resources, and safety, including Equal Employment

Opportunity, Americans with Disabilities Act, Family Medical Leave Act, Fair Labor Standards Act, and Occupational Safety and Health Administration, within one of the company's operating regions that provides electric service to customers. This includes conducting investigations to ensure fair and quick resolution of employee relations and safety issues; facilitation of research, analysis, and written responses to EEOC, Department of Labor, and OSHA inquiries ensuring expedited issue resolution and compliance; handling employee benefits and other human resource policy inquiries; employee safety; and development of training needs for the region.

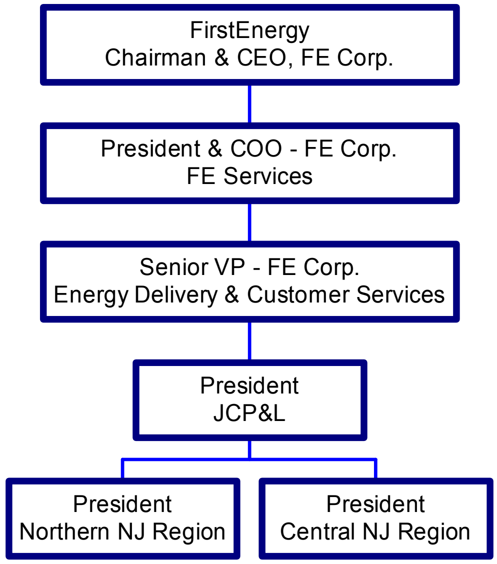
Director, Regional Customer Services
Responsibilities include planning and execution of customer services work processes within one of the company's operating regions that provides electric service to customers, including regional customer accounting, ensuring accurate and timely meter reading and field collection activities, and completion of regulatory mandated work. Promotes a safe work environment.

Director, Regional Customer Support Services
Responsibilities include directing all customer activities relating to installation of service and communications with major customers within one of the company's operating regions that provides electric service to customers, including managing the relationship between the region and major commercial, industrial, and governmental customers to improve and enhance customer satisfaction; negotiation and development of special contracts with major customers, which involves determining appropriate tariffs; consulting services for all customer classes, including commercial/industrial customers and large residential builders.

Area Manager
Responsibilities include execution of policies and programs to enhance the company's standing within one of the company's operating regions that provides electric service to customers, including creating and maintaining relationships with community leaders such as elected officials, key business leaders, non-profit organizations and educators. Serves as customers' liaison for operational activities, service quality, and reliability.

With respect to governance, the Region Presidents are not far removed from the FirstEnergy Chairman and CEO. Figure 11 shows the FirstEnergy organization in terms of reporting responsibility:

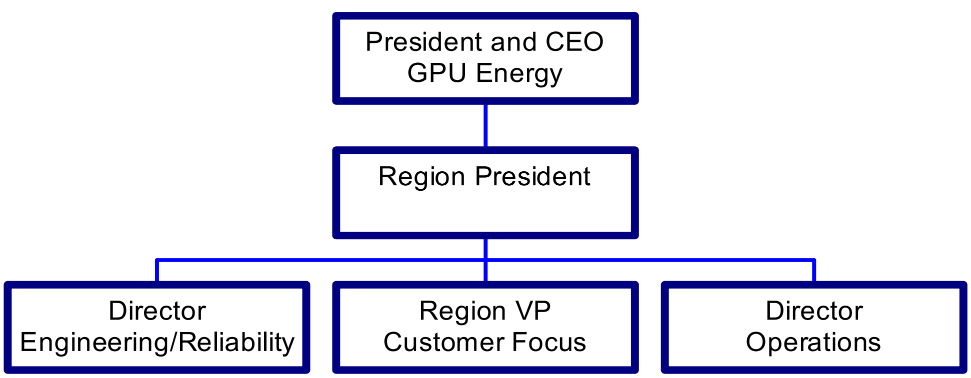
Figure 11
FirstEnergy Management Responsibility



The FirstEnergy senior leadership, with approval by the Board of Directors, sets Regional budget levels. The Regional President and his staff of Directors develop the projects to be funded within the budget limits.

Prior to the FE/GPU merger, GPU Energy also used a regional approach to organization, having evolved into four operating regions and assorted support functions. The GPU system contained the following Regions: Northern New Jersey, Central New Jersey, Eastern Pennsylvania, and Western Pennsylvania. Figure 12 shows the identical organization for each Region at December 31, 2000:

Figure 12
GPU Energy Corp. Organization



FirstEnergy's form of organization is a future decentralization of functions begun by GPU Energy in 1999 and 2000. However, FirstEnergy moved away from the GPU process-based, self-directed workforce that was used during the 1999-2000 time frame.

On December 11, 2003, FirstEnergy announced election of a new President of JCP&L, effective January 5, 2004, who has ultimate accountability and responsibility for New Jersey operations. Reporting to the President of JCP&L will be the Regional Presidents of the Central and Northern Regions.

Staffing

The Staffing history for JCP&L has been affected by several major organization restructurings. In 1994, a voluntary early retirement plan was offered that resulted in the number of fulltime JCP&L employees falling from 3,447 in 1993 to 2,759 in 1995. In 1996, the number of employees was again reduced to 2,512, which remained at 2,512 for 1997. This reduction resulted from the formation of GPU Energy by combining all transmission and distribution operations, the formation and spin-off of a separate generating company with approximately 2,200 employees, and a second voluntary early retirement plan. JCP&L employees since 1998 are shown below in Table 20:

Table 20
JCP&L Fulltime Employees

	JCP&L Management			**JCP&L Bargaining Employees**			**JCP&L System Total**		
	NNJ	CNJ	Total	NNJ	CNJ	Total	NNJ	CNJ	Total
1998			215			1619			1834
1999			210			1607			1817
2000	119	93	212	609	761	1370	728	854	1582
2001	151	125	276	601	749	1350	752	874	1626
2002	159	129	288	582	740	1322	741	869	1610
2003	173	141	314	562	708	1270	735	849	1584

JCP&L's bargaining unit members are protected against involuntary layoffs through October 2004. The reductions occurring in Bargaining Employees have been through retirements and voluntary separations. With respect to management employees, the Stipulation of Settlement approved March 13, 2003, in Docket No. EX 02120950, specified in Paragraph 3 – "JCP&L shall increase its New Jersey employment by at least 40 new fulltime employees within planning, design and protection engineering, dispatching, relay testing, substation operations and maintenance, forestry, customer service and/or line operations and maintenance at the Company's discretion." JCP&L chose to add management employees as opposed to bargaining members performing line O&M.

On November 20, 2003, an extensive interview was conducted of the regional presidents, Mr. Steve Strah, president of the Northern Region and Mr. Don Lynch, president of the Central Region. The purpose of the interview was to fully explore the management philosophy and discuss what has been generally determined through the other investigation and interview process and field assessment. The primary goal of the interview was to determine if the FirstEnergy corporate philosophy and if the philosophy of management in the two regions and Jersey Central overall was reflected in the actions of management, subordinate and construction personnel at all levels and also reflected in the system assessment. Additionally, this interview was to determine if the presidents were aware or cognizant of the deficiencies in subordinates' philosophies determined through the assessments completed to date by Booth & Associates, Inc. personnel. Furthermore, the interview was to determine what actions were in place and what actions are contemplated to rectify deficiencies which have been identified by Booth together with deficiencies which have been identified to date by Jersey Central and other outside consultants.

The overall discussion of the FirstEnergy GPU merger integration indicated that both regional presidents were involved and aware of Jersey Central adopting the FirstEnergy tested "best practices and policies". They indicated that the integration was approximately 66% complete. They indicated that the "best in class" or otherwise known as "best practices" was predominantly an outgrowth of the Ohio Edison PAI's performance initiatives and that Mark Julian was one of the team members involved in this integration process. One non-FirstEnergy Company source for the "Best Practices" was Tampa Electric Company (TECO) in Florida per Mr. Strah. JCP&L also provided additional information on February 19, 2004 that the following IOU practices were reviewed and certain procedures incorporated into the FirstEnergy processes:

1. Duke Energy – storm restoration process (Communication Liaison role).
2. Florida Power & Light – storm restoration process (use of estimated restoration time).
3. Houston Lighting & Power Company – CRI (based on the framework of the concept used at HL&P)
4. Georgia Power – maintenance practices (gloving work practices for line personnel).

JCP&L provided the above examples but a complete list of best practices that may have been observed and integrated into the JCP&L/FE business processes was not provided.

The two regional presidents believe they are the driving force behind the management philosophy and the entire integration process of Jersey Central into the FirstEnergy corporate philosophy and culture. They anticipate they will reach 100% completion of the integration within the two year time frame, which is the end of 2004. The two regional presidents believe they work together as a team for the benefit of Jersey Central and FirstEnergy. They are embracing the FirstEnergy ”Best Practices” philosophies and methods and incorporating them into the Jersey Central way of doing business. Both regional presidents indicated that they firmly believe they have a substantial degree of autonomy and direction and budgetary control for their regions and for Jersey Central. They explained their chain of command and the need to meet goals and objectives of FirstEnergy including fiscal responsibilities. They also indicated that the prioritization and financial requirements for the Jersey Central system rests squarely with them. They indicated they did not believe that the necessity to meet prudent utility practice, reliability and safety requirements would be overridden by FirstEnergy management and management philosophy if the regional presidents recommended certain expenditures and practices be implemented. It should be noted at this point, that FirstEnergy restructured JCP&L. JCP&L announced on December 11, 2004 they have added Mr. Steve Morgan, the new President for JCP&L. There is no clear picture of how this may change the duties of Mr. Strah and Mr. Lynch.

In general, the two regional presidents believed that the order of priority among the stake holders was: 1) The customers and employees on a virtually equal stead, and then (2 either management and stockholders or stockholders and management in that order. Both regional presidents emphasized that overall service delivery was paramount for Jersey Central and was among their primary commitments. They emphasized on numerous occasions throughout the interview process that safety was their number one concern. The two regional presidents overall believe that the integration of the “Best Practices” philosophies and procedures of FirstEnergy is moving efficiently and well. They indicated that they have multiple reliability targets and goals which have come out of the FirstEnergy “Best Practices” including the CRI and CAIDI. They feel confident that they are exceeding the dollars per customer in the Jersey Central area as compared to the rest of the FirstEnergy companies. They have substantial financial obligations to FirstEnergy and to the commitment of meeting the reliability goals. They feel they have met and/or exceeded the regulatory oversight and orders that have come out to-date. They reiterated that safety was a key performance issue and that they had in place incentives under the KPI process.

Overall the presidents do believe their cost per customer is going down but not at the expense of reliability. They further indicated that they have internal reliability driven initiatives and that is, in part, causing the Jersey Central company’s cost to currently be higher than the rest of FirstEnergy. The regional presidents did indicate that they expect the BPU to allow them a return on rate base for the capital investment and dollars spent to enhance reliability.

Both regional presidents went on to indicate that although safety may not be exactly where they would like it, it is the number one foundation that drives everything. Mr. Strah indicated that there is nothing more important to the company than safety and that the manual of operations helps them move towards higher levels of safety. The regional presidents believe it is ultimately up to them to allocate resources. They further indicated that there is an overall effort to move towards standardization across the entire FirstEnergy Company. In regard to the overall reliability, they look at trends and their programs and their reliability issues are predominantly driven by CAIDI and the CRI trends.

The regional presidents both held the belief that most of their substations could be rated good, some would be average and some poor. They also graded their distribution system in a similar fashion with more of their distribution system rated good, some average and some poor such as sub-quality, older equipment. Similarly, they rated their outage response ability and capability to be good. Management and engineering are rated good to excellent. The union line workers are rated average. They also believe that they had a successful job training and safety program and procedures and philosophy.

The presidents during the interview made it clear they did not believe it was appropriate for the BPU or outside parties to mandate specific project or design issues to the company. They indicated they welcome reports and recommendations; they do not feel however they have been given sufficient recognition for what they have done to date. They used as an example the fact that they were mandated to install millions of dollars of spacer cable which in many instances was purely a waste of capital resources. They believed these dictated practices took away from other needed programs and emphasis on other more appropriate ways to improve reliability.

The regional presidents believe that their inspection of 100% of their over 1,000 circuits and the associated recommendations will be completed with the necessary corrective measures. The recommendations will be fully implemented and corrections in place by the summer of 2004.

The general tone and consensus of the regional presidents was a clear management commitment and philosophy to safety, reliability and customer service. They believe they are following the necessary management philosophy and procedures and processes to improve the Jersey Central system. They are firmly committed to the FirstEnergy best practices philosophy in all areas. They have indicated that they are ultimately responsible for the Jersey Central system and its success including safety and reliability. They indicated they believe they have been doing this and are currently doing this. Since the 11/20/03 interview, Mr. Steve Morgan has been recently brought in as the Jersey Central President, and Mr. Strah and Mr. Lynch will now report to Mr. Morgan. Although Mr. Morgan was not interviewed, Booth has held several telephone conferences with Mr. Morgan. Mr.

Morgan comes to Jersey Central with high regard within FirstEnergy and outside utilities. Mr. Morgan, in the conferences, has exhibited a substantial knowledge of electric utility construction, operations and maintenance practices, including outside electric distribution plant. Booth has determined that Mr. Morgan brings to Jersey Central management expertise at the top that understands electric distribution infrastructure and operation. Booth believes if given the authority and resources, Mr. Morgan has the skill set to recognize the improvements required at all levels. He stated he has reviewed, in the field, most of the system. We feel he can recognize the deficiencies and provide the badly needed management direction through knowledge-based assessment to implement the necessary short- and long-term improvements and programs to raise the system reliability to acceptable levels.

During the interview process the most predominant theme was that of safety. Although safety may be among the highest priorities in the company's management philosophy, it is not reflected on the system or through the many actions of the company staff. This is among the most glaring areas in which there is a significant incongruence between the stated management philosophy and goals of the regional presidents and FirstEnergy and the actual system condition, practices, processes and procedures. The significant disconnect between management's stated philosophy and goals in regard to safety and the system condition and actions of Jersey Central's staff is extremely disturbing. Throughout the majority of the interviews, safety and safety related practices and the safe operation of a reliable electric system was among the highest goals discussed, not only by the regional presidents but by many of the other management level individuals interviewed. However, as part of these interviews particularly with many of the management level individuals and also with the regional presidents, many of the standard utility practices and procedures that are well known to lead to a well constructed and safe electric utility system are not in place at Jersey Central or FirstEnergy's best practices. Furthermore, there appears to be a large disparity between what management says takes place in the form of communications from lineman and supervisors and engineers to management and what Booth has determined is actually taking place both in terms of real communication, actions associated with communication of problems and the implementation of corrective measures to correct or mitigate safety issues.

The following will be a specific discussion of numerous categories within construction and safety in which management philosophy and actual implementation clearly are incongruent and contribute to not only a reduced level of safety but also the potential for inherent reliability problems. Management states, "Lineman and supervisors are the eyes and ears in the field." This is not, however, reflected in the maintenance and operations practices of the Company.

Construction

Jersey Central has had in place construction standards and Jersey Central has not fully adopted the FirstEnergy construction standards including materials and practices. Management believes it is following FirstEnergy's best practices in its design and construction process including the implementation of its standardized specifications and construction standards. The construction standards and specifications are discussed and dealt with in detail under that category in this report and will not be discussed in detail at this time. The process however, which is necessary to assure safety both of the employees and the public and intended to assure an adequate level of reliability is in of itself substantially deficient. Management, including the regional presidents, believes they are following best practices. Our assessment and questions at all levels indicate that there are many standard utility practices including FirstEnergy practices which are necessary to assure that construction follows the standards and is safe for the employee and public that are deficient or are simply ignored.

Through the interview process, we have determined that there appears to be a substantial lack of engineering, including line staking and design associated with distribution line construction. Most construction seems to be driven from the line superintendent level. Furthermore, the line foreman is responsible for checking the construction and the "as-building" of the construction drawings. The line foreman and his line crews are the very ones constructing the facilities. Self-inspection, by having the construction staff inspect its own work, fails to provide the most rudimentary level of quality control. The regional presidents even admitted there was no formalized inspection process. This was reiterated throughout all of the discussion with other management and construction personnel. A consistent theme in the electric utility industry is "you get what you inspect, not what you expect". For the distribution line design, staking and construction process there appears to be a complete lack of training for design and staking engineers, a lack of staking manuals with such procedural items as transverse loading calculations, conductor sag and tension requirements, guying and anchor design requirements just to mention a few. Furthermore, when a line is constructed or maintained where upgrades are performed there is no formal inspection process producing discrepancy reports and correcting improper or deficient construction items. Specific action items and recommendations will be contained in that section of this report to deal with this significant deficiency. This area of deficiency is one of the leading causes of poor reliability. If the company does not build it correctly, it will ultimately result in reliability problems.

Booth & Associates, Inc. as part of the iterative process of attempting to reach concurrence with JCP&L on all recommendations has made significant progress. To the extent that JCP&L agrees to fully comply with its Asset Management Strategy (AMS) document including the CRI program, which agreement is reflected in the Stipulation of Settlement (which includes the published

AMS to which JCP&L has agreed to abide) entered into on June 8, 2004 by JCP&L and Board Staff (and which was reviewed and adopted by the Board), our concerns in this area have been addressed.

Safety

The Presidents voiced their opinion that there is nothing more important within JCP&L than safety. Improved training and safety processes are necessary to elevate the field safety procedures to the management's stated priority. As discussed previously, JCP&L's practices for grounding substation fences does not meet NESC Code requirements and industry standards. JCP&L does not extend bonding conductors to the barbed wire at the top of the fence but relies on the fence posts for bonding of the fence fabric. Any employee or member of the community in proximity to a substation fence during an electrical fault involving the substation will be subject to life-threatening voltages. Paragraph 2 of the MOU has addressed these concerns.

A significant number of padmount transformers also violates NESC Codes for security. Pentahead bolts have been removed by linemen during previous inspections and maintenance and not replaced. Paragraph 3 of the MOU has addressed these concerns.

In many of the 34.5 kV locations, surge arresters have been installed on the top phase. These arresters are not properly grounded; instead, the guy wires have been used to ground the arresters. In the event of a lightning strike to the top phase, the fault current traveling down the guy wire into the ground could seriously injure anyone standing near the guy wires, particularly in cases where the guy wires are not grounded. Guying and grounding construction practices as observed during the field investigations do not comply with the JCP&L and FirstEnergy construction standards in certain instances. The MOU has addressed these concerns and to the extent that JCP&L agrees to fully comply with its Asset Management Strategy (AMS) document including the CRI program, which agreement is reflected in the Stipulation of Settlement (which includes the published AMS to which JCP&L has agreed to abide) entered into on June 8, 2004 by JCP&L and Board Staff (and which was reviewed and adopted by the Board), our concerns in this area have been addressed.

RDO

Our interviews and site visits to the Morristown and Reading RDOs revealed several problems. The one major deficiency appears to be a lack of documented equipment operating procedures. This deficiency appears to exist across all of the dispatch centers. Furthermore, there is also a lack of alarm points set in a manner to assist the operators during the emergency restoration process.

The Special Reliability Master in his Interim Report identified the need for additional training for dispatchers. He also noted that the organization of the RDO does not have a lead or senior dispatcher even though there is a job description for such a position in the present organization. This is one area that Mr. Morgan will need to address and points out again the insufficient supervisory-level intermediate management currently lacking in the JCP&L organization. During our interview of the Regional Presidents, they were unaware that the PowerOn circuits currently were manually built and updated, and that the lower level management did not want the transfer of GIS data to be automated. This supports our recommendation that the new President of JCP&L institute a management audit which specifically focuses on the deficiencies in management and engineering staff between the senior management level and the operations and maintenance and construction level.

As indicated in the Executive Summary, Booth & Associates, together with Board Staff and the Company engaged in an iterative process which made significant progress towards addressing all recommendations and, insofar as the issues discussed above are concerned, to the extent that JCP&L agrees to fully comply with its Asset Management Strategy (AMS) document including the CRI program, which agreement is reflected in the Stipulation of Settlement (which includes the published AMS to which JCP&L has agreed to abide) entered into on June 8, 2004 by JCP&L and Board Staff (and which was reviewed and adopted by the Board), which resolves these concerns.

7. Maintenance Systems, Policies and Practices

O&M Budget

Operation and Maintenance expenditures for Transmission and Distribution are shown below in Table 21:

Table 21
T&D O&M Expenditures
1998-2002

Region	1998	1999	2000	2001	2002
Northern					
Operating	*	*	$ 27.1 million	$ 39.0 million	$ 31.0 million
Maintenance	*	*	24.2 million	31.3 million	23.3 million
NNJ Total			$ 51.3 million	$ 70.3 million	$ 54.3 million
Central					
Operating	*	*	$ 29.2 million	$ 36.0 million	$ 36.8 million
Maintenance	*	*	35.5 million	26.2 million	20.0 million
CNJ Total			$ 64.7 million	$ 62.2 million	$ 56.8 million
System					
Operating	$ 62.6 million	$ 56.0 million	$ 56.3 million	$ 75.0 million	$ 67.8 million
Maintenance	43.6 million	65.5 million	59.7 million	57.5 million	43.3 million
JCP&L Total	$106.2 million	$121.5 million	$116.0 million	$132.5 million	$111.1 million

* *Data not available*

Total 2003 Budget T&D O&M expenditures were $161.2 million, which included an incremental $21 million for JCP&L's Accelerated Reliability Improvement Plan.

T&D O&M costs include expenses associated with labor, supervision, materials and supplies, and engineering used in the operation and maintenance of the Transmission and Distribution System.

Transmission Operations Expenditures includes operations supervision and engineering, load dispatching, station expenses, overhead and underground line expenses, transmission of electricity for others, miscellaneous expenses, and rents.

Transmission Maintenance Expenditures includes maintenance supervision and engineering and maintenance of structures, station equipment, overhead and underground lines, and miscellaneous transmission plant.

Distribution Operations Expenditures includes operations supervision and engineering, load dispatching, overhead and underground line expenses, street lighting and signal system expenses, meter expenses, customer installation expenses, and rents.

Distribution Maintenance Expenditures includes maintenance supervision and engineering and maintenance of structures, station equipment, overhead and underground lines, line transformers, street lighting and signal systems, meters, and miscellaneous distribution plant.

Transmission O&M costs in 1998 were 25% of Total T&D O&M expenditures ($27 million/$106 million). In 2002, Transmission O&M costs were approximately 20% ($23 million/$115 million).

Figure 13
O&M Budgets FirstEnergy Operating Utilities
($ million)

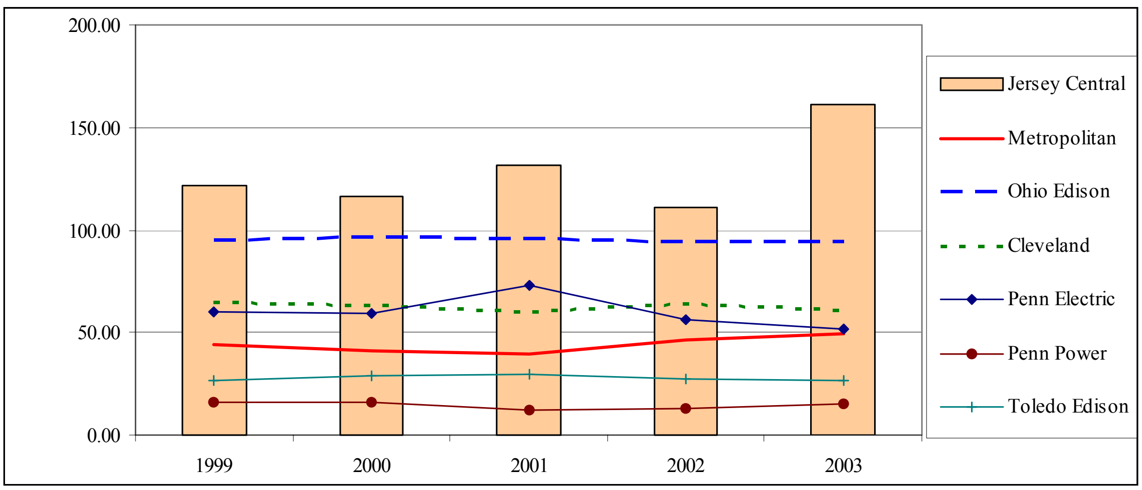


Figure 13 shows a comparison of JCP&L's O&M budget for a five-year period compared to FirstEnergy's six other operating companies. As discussed previously, comparison of the O&M expenditures for JCP&L must be viewed in light of the 24% higher cost for electrical construction experienced in New Jersey compared to Ohio. Increased levels of O&M spending for JCP&L in 2001 and 2003 are due to the Accelerated Reliability Initiatives implemented by JCP&L.

Distribution O&M expenditures expressed on a per-kilowatthour, percentage of total utility plant, dollars per consumer, and dollars per mile are shown in the following figures:

Figure 14
JCP&L Distribution O&M Expense per Kilowatthour Sold

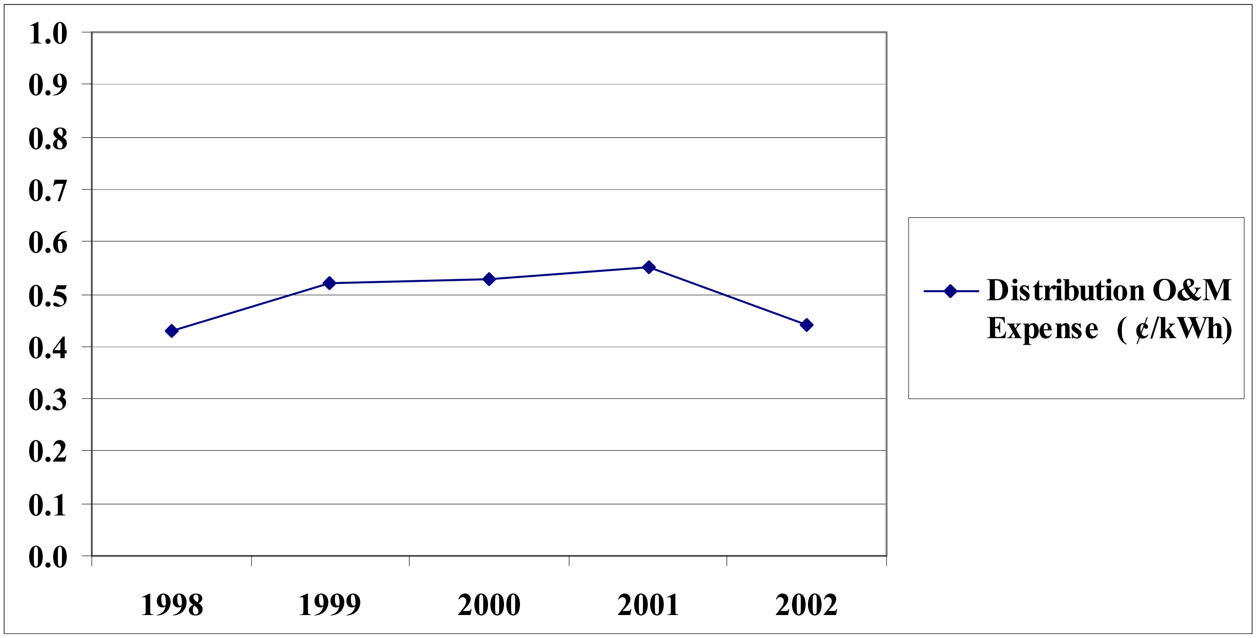


Figure 15
JCP&L Distribution O&M Expense as a percentage of Total Utility Plant

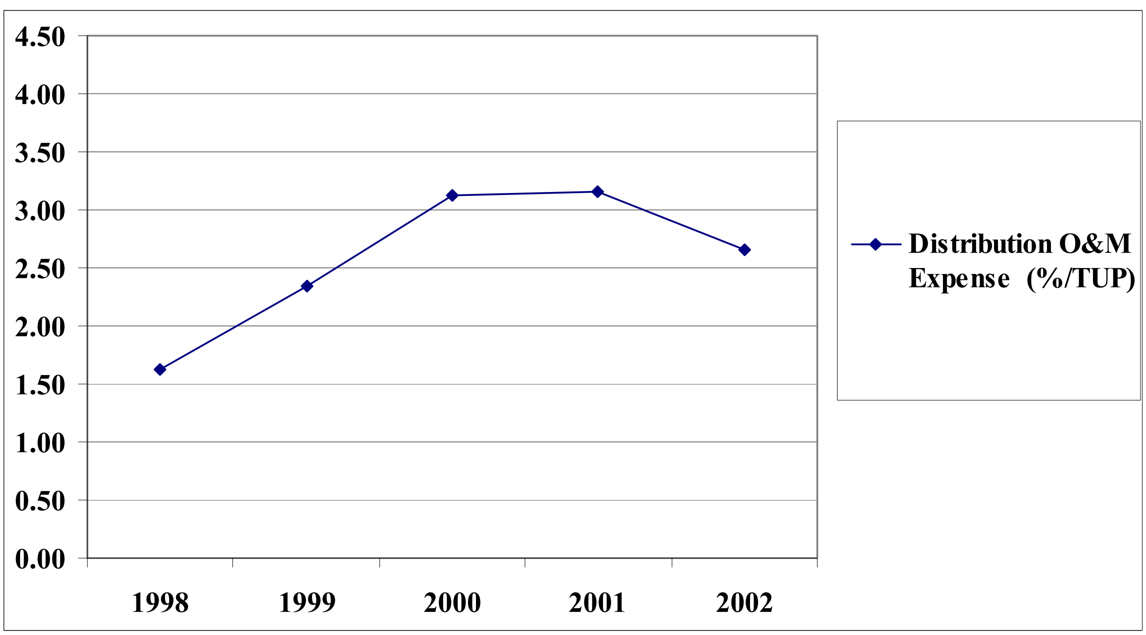


Figure 16
JCP&L Distribution O&M Expense – Dollars per Consumer

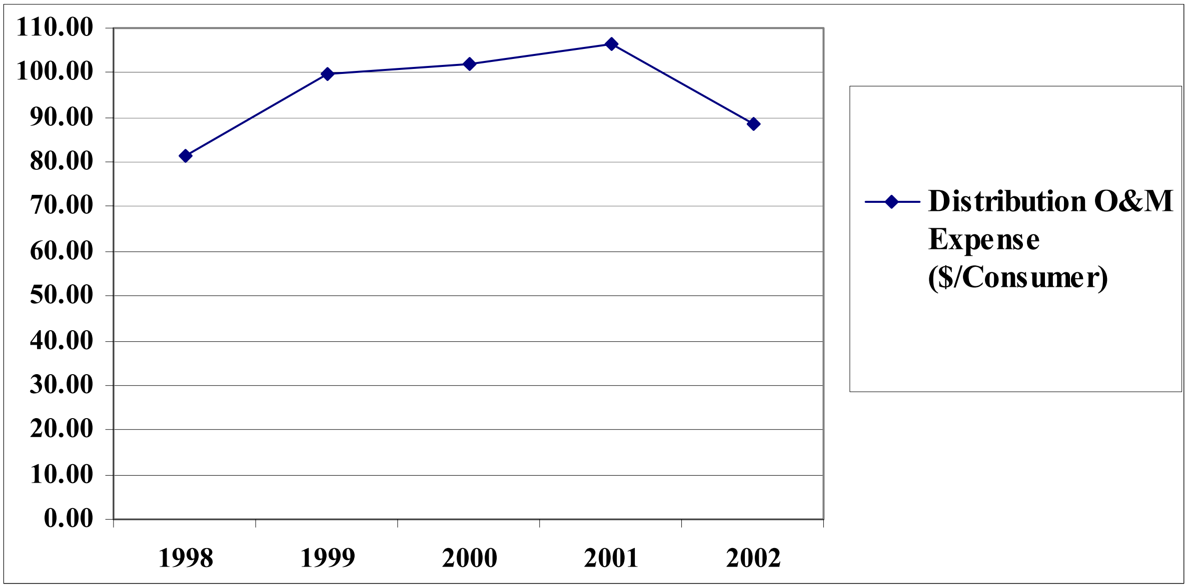
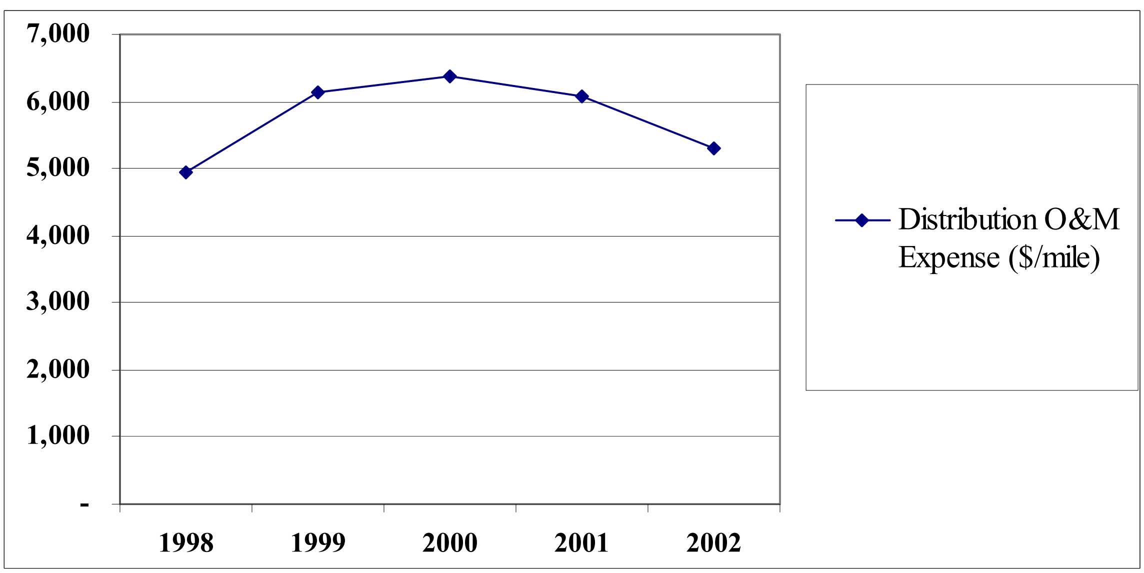


Figure 17
JCP&L Distribution O&M Expense – Dollars per Mile



Details for the above time trends are shown in Appendix F. In Appendix F we present results of a detailed calculation of selected financial and operating ratios for JCP&L with comparisons to the other six operating utilities of FirstEnergy. This analysis presents data for 14 categories of operating ratios for JCP&L for five calendar years, 1998-2002, with comparisons to Cleveland Electric Illuminating Company, Metropolitan Edison Company, Ohio Edison, Pennsylvania Electric Company, Pennsylvania Power Company and Toledo Edison Company. Statistics as well as ratio calculations for the following key Operation and Maintenance ratios are presented:

1. Distribution O&M Expense - ¢/kWh
2. Distribution O&M Expense - $/consumer
3. Distribution O&M Expense - $/mile
4. Distribution O&M Expense - % of Total Utility Plant
5. Distribution Plant In Service - ¢/kWh
6. Distribution Plant In Service - $/consumer
7. Distribution Plant In Service - $/mile
8. System Losses - %
9. Average Consumers per mile - consumers/mile
10. Materials & Supplies - % Total Utility Plant
11. CWIP/Plant Additions - %
12. Net New Plant/Total Utility Plant - %
13. Growth in Customers - %
14. Growth in kWh Sales - %

These ratios can be used as a tool in assessing electric utility performance. They do not provide definitive information nor do they establish a correct level of performance. Factors that may influence the ratios among utilities include:

- Number and composition of customers served
- Geographic location
- Population density
- Financial and management policies of the utilities

The ratios are calculated using calendar year data from the FERC Form No. 1 Database. The public version of the Form 1 Database is available for download and is viewed with the Form 1 Database Viewer, which can be installed from the FERC website – http://rimsweb2.ferc.fed.us/form/viewer/. All data used in the calculation except for miles of Distribution Circuits were obtained from FERC. Circuit mile data for the FirstEnergy utilities was obtained from SEC Form 10 filings.

Also contained in Appendix F is a similar key ratio analysis Booth performed for the Rhode Island Public Utilities Commission. This analysis presents data for the same 14 categories of operating ratios for the Narragansett Electric Company for five calendar years 1996 through 2000, with comparisons to six nearby New England utilities – Boston Edison Company, Commonwealth Electric Company, Massachusetts Electric Company, Western Massachusetts Electric Company, Public Service of New Hampshire and Granite State Electric.

Normally an analysis is conducted comparing a utility's expenditure on O&M with a peer group, such as other Regional or FE operating utilities. For example, using the Calendar Year Ended December 31, 2000 for comparison purposes, Distribution O&M expense expressed as a ¢/kWh figure shows:

Table 22
Distribution O&M ¢/kWh

Utility	Distribution O&M ¢/kWh
Ohio Edison	.16 ¢/kWh
Penn Power	.28
Toledo Edison	.29
Met Ed	.29
CEI	.29
Penn Electric	.38
Public Service of N.H.	.39
Granite State	.51
Mass Electric	.51
Western Mass	.51
JCP&L	.53
Narragansett	.53
Boston Edison	.56
Commonwealth Electric	.78

Looking at another important statistic, Distribution Plant In Service expressed as a ¢/kWh figure shows:

Table 23
Distribution Plant In Service
¢/kWh

Utility	Distribution Plant IS ¢/kWh
Toledo Edison	5.36¢/kWh
Ohio Edison	5.60
CEI	5.81
Penn Power	6.59
Public Service of N.H.	8.08
Met Ed	8.56
Granite State	9.76
Penn Electric	10.12
Western Mass	10.65
Mass electric	11.18
JCP&L	11.50
Commonwealth Electric	12.05
Boston Edison	12.46
Narragansett	12.82

Note that JCP&L's Distribution O&M expenditure and Distribution Plant In Service figures are comparable to other regional utilities except Public Service of New Hampshire, which is currently subject to investigation of its reliability by the New Hampshire Public Utilities Commission. Given the results of our infrastructure condition assessment, however, it is clear that past expenditures have not been sufficient to keep the JCP&L system in a well maintained condition, even if they are comparable to regional utilities or higher than FE's Ohio and Pennsylvania utilities.

Inventory costs in material and supplies were $1,341,195 in 2002 for JCP&L, compared to an average of $22 million for the FirstEnergy operating companies. JCP&L, in data provided on February 19, 2004, indicated that FERC Form 1 data for 2002 reflected a transfer of inventory by the GPU Operating Companies to GPU Service, Inc. in January 1999. JCP&L indicated that according to system accounting records, the average inventory level for 2002 for inventory devoted to JCP&L was $23,862,072.

During our interviews, employees complained that inventory and equipment have been reduced below adequate levels. Crews had to wait for transformers and poles to complete work orders and there are not enough bulbs in inventory to do streetlight maintenance in a timely manner. A change in inventory practice was also cited. Previously, transformers that were removed from service were brought in for inventory, serviced and returned to inventory in good condition. The new practice is to reuse transformers taken off the line without servicing them. JCP&L's regional presidents have the responsibility to set inventory levels. During our interview, the regional presidents indicated that material availability was good. Mr. Lynch stated that there had been problems explaining to employees that the economic process may result in certain items not being available. Mr. Strah felt JCP&L had experienced growing pains, and that certain line district locations had too high stock levels that were being drawn down. Further analysis is presented in Section 10 during our discussion of JCP&L's compliance with Stipulation 40 of the FE/GPU Merger Agreement.

Maintenance Processes and Systems

In June 2003, JCP&L moved to SAP/CREWS system for work management for execution of the maintenance plan, recording the work and assets' condition and reporting. SAP is the core computer software platform selected by FirstEnergy during the merger integration. Operations groups use SAP to schedule and manage work. Customer service functions use SAP for regulated distribution functions such as billing, credit and collections, and operation of call centers. Support functions such as supply chain, finance, and human resources also use SAP to support business units.

The Customer Request Work Scheduling (CREWS) system was selected to serve as the primary work management tool for energy delivery in the FirstEnergy system. CREWS is used to route work, design, estimate, plan and approve jobs; manage tasks; schedule material and resources; and record work hours and job completions. SAP supports energy delivery work where it ties in with Customer Care and Support Services operations. It is also the primary tool used to manage equipment maintenance across all work groups.

All customer information is stored in SAP. Systems used by distribution, such as the Automated Mapping/Facilities Management (AM/FM) software, access customer data stored in SAP. A Customer Care and Services (CCS) module automatically completes a number of tasks that have been performed manually. With respect to Customer Billing, SAP will issue notices on overdue accounts automatically. It will create call lists for phone collections and initiate work requests for disconnection of service. General Ledger accounts updates will be performed automatically instead of through manual entries for all invoices, payments, and adjustments performed in the CCS module.

It appears, based on our interviews and site visits, that Jersey Central and its parent company, FirstEnergy, have been implementing numerous automated systems intended to improve efficiency and reliability. These systems continue to be in a state of flux, and based on the assessment at the time this report is published, the systems are in many cases continuing to evolve through modifications and upgrades and software additions and changes. To a significant degree, it appears that Jersey Central and First Energy have been automating manual processes.

Furthermore, it appears this has been done and continues to be done in a manner which lacks complete forethought and planning based on developing strategic goals and defined needs to be met through automation. The evaluation of the array of systems and the fact that some automation implementation is determined to be changed within three to four months of implementation, with the changes reimplemented within seven months of the change, indicates poor planning and forethought and possibly inadequate investigation of the success of implementation by other utilities or similar automated processes. This includes but is not limited to the 21st Century automated Call Center.

The systems reviewed, and for which there were interviews to determine the implementation process, utilization, training, and future enhancements, include SAP, PowerOn, CREWS, 21st Century and the IVR system, AM/FM, the automated regional dispatch operation, and the automated dispatch center in Reading, Pennsylvania, and the associated continued enhancement of hardware and software. Each of the above systems will be discussed in greater detail throughout this section. Overall, it is apparent that First Energy and Jersey Central are attempting to implement a great deal of "state of the art" automation which has been determined across the electric utility industry to enhance customer response and improve outage management and reliability. Although this is admirable, and in today's environment it is essential, there appear to be many deficiencies with the current status and implementation process. Furthermore, it must be recognized by the utility, the BPU, and the customers that simply purchasing, installing, and operating "state of the art" software and automated processes, does not in of itself mean improved reliability or efficiency. Simply automating manual processes can be detrimental to overall system efficiency and reliability if this automation implementation is not first preceded by a clear plan of goals and measurable achievements to be met by the automation processes. Furthermore, as indicated in other sections of this report, automation will not improve reliability if the system with which it is to monitor and operate is either (1) not in adequate condition currently or (2) is not well maintained and the system cannot sustain itself at prudently acceptable utility standards and levels. Simply stated, automation at any level is not a substitute for a well designed, constructed, and maintained electric system infrastructure. Automation will only make you aware of the outages and problems on a marginally faster and more accurate basis. In fact, the significant investment in machines, software, training and personnel required to implement automation should only come after the system infrastructure, capital investment and operation and maintenance investment is sufficient enough to carry on a robust system that at least meets acceptable prudent utility standards and practices. The following will be a discussion of each of the automation systems as they relate to the utilization for system reliability purposes.

SAP

SAP is simply integration software that allows the input of information and the data retrieval and inquiry of information and dissemination of information among staff and other software. In fact, it serves as the operating platform for most of the standard operating procedures associated with the outage management systems, Call Center, construction management, and AM/FM systems. From all indications, it is a sound and prudent selection by First Energy and Jersey Central. It serves and meets the needs of the utilities operations. In of itself, it does not detract or enhance system reliability. It simply serves a valuable function for the management of substantial data, information and communication.

CREWS

CREWS does appear to be a workforce management system which is equal to other automated workforce management systems implemented within the electric utility industry. The CREWS system does, however, have the clear appearance of operating as an automated process to a previously manual process without utilizing its full capabilities and without utilizing the information and data available to assure response to system reliability needs and enhancements. Although the planning process will be discussed in a separate section, it is very important to point out that the manager of planning did not appear to us to have available to him nor did it appear to us that he avails himself of the data available and provided through the CREWS automated system for consideration in his short- and long-range planning process. The manager of planning does not appear to use valuable data and field information from the CREWS processes in evaluating budgeting needed for operation and maintenance activities.

During the interview process, the Jersey Central personnel spent a great deal of time pointing out the tremendous value of CREWS and their methods of weekly and monthly meetings intended to identify the operation and maintenance needs of the system for not only workforce management but also for outage management and system reliability and maintenance issues. What we heard in these interviews with managers is the way we believe the system should function. What we have seen in reality and heard from the field personnel is that the system does not function as stated by management and staff. The identification and notification in the meeting process by lineman to management do not continue through communication process to planning and actions.

There is a significant void between the stated intent and purpose and defined functionality and reality of the system. CREWS is an automated process in which Jersey Central personnel have stated its enhancement to overall reliability, system operations and improvement that is not reflective in the reality of the system infrastructure. The electric system infrastructure has been and continues to be an obvious low priority. Distribution facilities are not prioritized from the standpoint of urgent operation and maintenance, upgrade and improvement needs.

Absent field investigation and discussions with the construction personnel, one would believe that First Energy and Jersey Central had implemented a superb workforce management software system and procedure. This is not, however, reflected in the reality of the electric distribution system or planning process. As stated elsewhere in this report, the Booth field investigation should not have identified approximately ten percent of the system which is unsatisfactory. Furthermore, another twenty-five percent of the system which is poor and needs immediate attention (RDO) is too high if facilities asset management was a complete process. The construction workforce indicated it is not given the resources to repair the needed system deficiencies. In some cases, the same deficiencies have been reported for years and yet not placed on a list for correction in the purported sophisticated CREWS system and process.

T&D Planning and Operations

Planning and operational control for extra high voltage transmission facilities (500 kV, 230 kV, 115 kV) has been turned over to the PJM RTO. PJM monitors operation of facilities down to the 115 kV level. Operation of 115 kV transmission is controlled from the Reading Transmission System Control Center. This Transmission Dispatch Center is responsible for controlling all of the bulk transmission of JCP&L, Penelec, and MetEd, and the operation is integrated with the FirstEnergy control center in Wadsworth, Ohio. Many of the operating practices are governed by PJM. PJM dispatch models are global in nature and allow PJM to re-dispatch generating facilities and control voltage levels. The Reading Dispatch Center conducts more detailed modeling at the 115 kV and higher level.

The Regional Dispatching Office (RDO) presently located in Morristown is responsible for controlling the subtransmission (34.5 kV) and distribution systems. Jersey Central is moving from a single RDO to separate RDOs for the Northern and Central regions. The RDOs are provided with state of the art automation equipment and energy management systems. As discussed in this report, Jersey Central personnel believe that moving from a single RDO for New Jersey to a separate RDO in each region will be a significant enhancement. We believe this will be an enhancement, because you will have an RDO that is manned by personnel within that region and who should have a sense of the infrastructure within that region together with geographics. More importantly, based on the interviews and observations, it is believed that Jersey Central and First Energy are training the new dispatchers to be placed at the two regional RDOs in a very comprehensive and systematic manner. One of the most important training procedures is the week that the new operators spend at the Reading Transmission Dispatch Center. At this facility, these personnel are not only trained on the energy management systems, they also meet and learn the operating methods of the transmission system dispatchers with whom they will interface. Even more importantly, they learn and understand the many modeling, fault analysis and other predictive tools and knowledge resources available at the Reading transmission dispatch facility. This will inherently provide Jersey Central with superior training, knowledge and interface capability to additional backup resources and more highly sophisticated resources. This can only serve to improve the efficiency and operation of the dispatch center which is the heart of system outage restoration.

The Reading Transmission Dispatch Center is implementing new hardware and software which is intended and should provide enhanced ability to support the RDOs. Because of the significant hardware and software changes and the de-centralization of the RDOs (RDOs in the Northern and Central regions), it would be important for the Board to review the success of this change six months after full implementation and again at the one year anniversary. All indications in the current review are that these dispatch center changes will clearly enhance Jersey Central's ability to identify problems and react more efficiently and effectively for outage restoration purposes. As with any change, it will take at least one year to be able to assess whether this change has been effective and accomplishes the goals.

During the review process, including interviews and discussions at the RDO, both in Reading and Morristown, it was determined that neither FirstEnergy nor JCP&L RDO personnel were aware of the details of the facility connection requirements as outlined in the Open Access Transmission Tariff. Furthermore, it appeared that there was no procedure within the companies to enforce the requirements of the PJM Facilities Connection Requirements. Additionally, throughout the interview process, all of the various Jersey Central and FirstEnergy management personnel, there appeared to be virtually no understanding of the existence or monitoring of any of the performance requirements or general requirements which are typically and consistently outlined as part of facility connection requirements and would be issues which would directly affect reliability and enhancement of interconnection of transmission and distribution substations to the transmission system and the generation provider. It is generally the rule with FERC that the interconnecting distribution company, whether a separate entity such as an electric co-op connecting to an investor-owned utility or an investor-owned utility connecting its own transmission to distribution substations to the transmission system, are required to follow the same standards and for those standards to be enforced. Jersey Central should have in place the knowledge and provisions within their RDO and their management operating personnel to meet the facility connection requirement standards and to enforce the standards.

We have determined that there is a lack of standards through implementation and enforcement of major areas such as power factor correction, voltage unbalance, and undervoltage monitoring, and power quality issues. Power quality issues include, but are not necessarily limited to, voltage flicker, harmonic content and harmonic distortion, temporary overvoltage, transient overvoltages, voltage unbalance, power factor, and transmission system interruptions. Although Jersey Central seems to have a policy of significant fixed capacitor additions in an effort to attempt to provide for the maximum possible voltage correction through utilization of capacitors, there seems to be little or no attention to power factor levels at substations. This means that power factors can be substantially deficient, either by being too low, or even worse, at light load periods, substantially too high. The excess leading VARs can result in many power quality problems with the customers and the system including harmonic distortion problems, and overvoltage conditions. Furthermore, leading power factor can result in substantially inflated power losses just as significant lagging power factor can result in higher power losses. Furthermore, leading power factor can result in capacity transformation equipment capacity problems to the same extent that lagging power factor contributes. All of these issues must be monitored to appropriately and optimally operate a system.

RECOMMENDATIONS

We recommend that management and staff personnel responsible for planning, capital improvements, and the RDOs have copies of the PJM *Facility Connection Requirements* and are completely cognizant of the operating standards contained therein and apply these standards as rigidly to each of their substations and delivery points as the generation transmission utility would impose on any other interconnecting customer. Jersey Central should be able to review these facility connection requirements and develop a plan and process by which to implement the standards outlined in the PJM *Facility Connection Requirements* within a 12-18 month period. This would include educating and informing the RDOs and the planning engineers.

At the RDO level associated with the operation of the distribution systems, the one deficiency appears to be a lack of documented equipment operating procedures. This deficiency appears to exist across all of the dispatch centers. Booth believes that written operating procedures for the critical components and equipment combined with appropriate alarm points on the equipment and components will enhance the RDO operations. Booth does believe that the current training process dictated by moving to RDOs in each region is an effective tool to substantially improve the RDO operating procedures. We are, however, confident that there is a significant lack of documentation and knowledge currently at the Regional Dispatch Office as it relates to Facility Connection Requirements operating procedure details associated with specific switches and equipment. Furthermore, there is also a lack of alarm points set in a manner to assist the operators during the emergency restoration process.

Paragraphs 1 and 5 of the MOU, which provide that JCP&L will continue and complete a specific 34.5 kV telemetry project and conduct a GIS field audit and provide status reports with respect thereto, address these issues and recommendations.

Maintenance Policies

During 2002, JCP&L transitioned most of its maintenance programs to FirstEnergy standards adopted during the merger integration process. Our engineers and Analysts have reviewed in detail the following programs:

- Vegetation Management
- Pole Inspection Program
- Substation Maintenance
- FE Planning Criteria
- T&D Standards
- ARIP

Vegetation Management

Under Section 57 of the Electric Discount and Competition Act of 1999, the New Jersey Board of Public Utilities must adopt appropriate standards to assure the continued provision of “high quality, safe and reliable service” to electric utility customers. Proposed rules have been drafted to ensure that New Jersey’s electric utilities meet uniform standards in the performance of vegetation management in and around their facilities.

Booth Engineers have reviewed the FirstEnergy vegetation management specifications and compared them to the specifications of other utilities with whom we are familiar, including Progress Energy, one of the ten largest investor-owned utilities in the country. In addition, the FirstEnergy standards were compared to the Rural Utilities Service (RUS) Guidelines utilized by nearly 1,000 utilities across the United States. Our analysis is described below.

FirstEnergy – Jersey Central Power and Light

Distribution Voltage Clearing Zone

FirstEnergy has established guidelines for right-of-way clearing based on a four-year clearing/trimming cycle. The clearances which have been established vary depending on the kV of each line and the type trees in an area which is to be cleared. New distribution line construction, which are lines 69 kV or less, are cleared in order to achieve four years of clearance or a minimum of 15’ either side of primary conductors. In cases where four years of clearance is unattainable, 12’ of radial clearance should be achieved. In some cases where 12’ is unattainable, structures with fuses or disconnects must have all woody vegetation cleared within an 8' radius of the fused/disconnect side of the structure.

Secondary Voltage Clearing Zone

Secondary circuits shall include all facilities between the transformer pole and the final pole on the line. Secondary voltage lines shall have a clearance zone extending 4' radially around the conductors.

Transmission Voltage Clearing Zone

Transmission lines operating at 23 kV-69 kV shall be cleared 15' from the conductor. Transmission lines operating at 115 kV-138 kV shall be cleared 25' from the conductor. Transmission lines operating above 138 kV shall be cleared 30' from the conductor.

Progress Energy

Distribution Voltage Clearing Zone

For Distribution class voltage construction 23 kV and below, Progress Energy tries to achieve a four (4) –year trim cycle; the standard calls for two (2) to four (4) years. For new construction of primary lines, trees must be pruned or cut to have a minimum of 15' of horizontal clearance radially from the primary conductor. There must also be a minimum of 6' of clearance underneath the primary neutral. In some areas where trees are "slower growing," such as hollies, magnolias, clearances may be reduced from 15' to 7-8'. In areas where "faster growing" trees such as maples, oaks, cutback should be 15'.

Within some cities and towns there have been restrictions put in place to limit the cutback of right of ways along city streets. As an example, in Raleigh, Progress Energy and the City of Raleigh have worked closely in enacting guidelines which allow Progress Energy to maintain distribution right of ways on a two-year trim cycle, the thought being that maintaining these corridors more frequently helps in reducing the visual effect of cutting back if done more often. This also limits the amount of cutback required on trees which are "faster growing" if done more often. Progress Energy tries to maintain a distribution system cutback average of once every four years. Currently they are averaging a distribution system cutback average of 3.25 years.

Secondary Voltage Clearing Zone

For secondary conductors, trees must be pruned or trimmed back a minimum of 10' radially from the secondary conductor. There should also be a minimum of 6' clearance beneath the lowest secondary conductor. For multiplex secondaries and services, trees should be trimmed or pruned enough so that there is no rub between the conductor and branches or limbs of the tree.

Transmission Voltage Clearing Zone

Transmission lines of 69 kV should be cleared 25’ each side the centerline. 115 kV transmission lines, right-of-way should be cleared 35’ each side the centerline. 230 kV transmission lines, right-of-way should be cleared 50’ each side the centerline. 500 kV transmission lines, right-of-way should be cleared 90’ each side of the center line.

The trim cycle for Progress Energy transmission lines is once every two-three years. The transmission system is patrolled three times per year. It takes two days to patrol a division and there are five divisions. All transmission right-of-way is flown by helicopter. Designated trees outside the right-of-way are removed if their projected path will interfere with the transmission line if the tree falls. Initially, all danger trees are removed, then danger trees are removed approximately every five to nine years after initial construction.

Rural Utilities Service (RUS) Guidelines

Distribution Clearing Zone

RUS does not specifically state an actual right-of-way width for 35 kV and below distribution line design. What RUS recommends is a 20’ wide right-of-way width. The actual right-of-way width is left to the discretion of the design engineer’s/owner’s choice, so there is no specific requirement for the actual maximum right-of-way width required. Notwithstanding the right-of-way minimums mentioned above, RUS does require its borrowers to comply with the National Electrical Safety Code. RUS expects it borrowers to look at the minimum provisions for each specific installation and to assure that all NESC provisions are observed. So if conductor swing is a problem, or something similar, and additional clearance is required, the borrower will design, construct and maintain the right-of-way accordingly. There are no RUS requirements for right-of-way re-clearing or re-cutting that we could locate. There also are no requirements for the growth cycle clearing.

Secondary Voltage Clearing Zone

We could not locate any RUS requirements for the right-of-way widths for secondaries and multiplex services. Each RUS borrower typically develops standards to be used as a guide in their particular area.

Transmission Voltage Clearing Zone

For transmission voltages of 69 kV and higher, RUS does not require specific right-of-way widths but instead recommends to its borrowers right-of-way minimum widths. The recommended right-of-way guideline suggests from the outside conductors, perpendicular from the ground, extending 5' to the edge of the right-of-way, then shooting a 45-degree angle from the perpendicular and clearing any trees which penetrate this plane. RUS again does not have any specific specifications for growth cycle reclearing and/or guidelines for herbicide treatment of existing transmission right of way.

Conclusions

Distribution Clearing Zones

The standard tree-trimming width for typical distribution voltages is 30', 15' on either side of the distribution construction. Right-of-way clearing for new installations for voltages 69 kV vary based on each company but generally require a right-of-way width of between 30'-50'. This of course would depend on the type of construction and line location. Lines which are rural are likely to have a full width right-of-way and lines inner city or suburban are likely to have narrower right-of-way widths. Right-of-way growth cycles are two to four years.

Secondary Voltage Clearing Zone

Secondary and multiplex right-of-way widths vary from 20'-30'. This is dependent on type of construction and line location. Multiplex and Triplex, Secondary and Service conductor right-of-way widths usually require that the right-of-way be cleared just enough to prevent conductor rub of any part of a tree. Most of these widths would normally vary from 2' radially to as much as 5' radially. The growth cycles for secondary and multiplex services would normally be performed at the same time as trimming for distribution voltage clearing zones. This would usually occur once every two to four years as concluded for distribution voltage clearing zones above.

Transmission Voltage Clearing Zone

For Distribution lines less than 69 kV, right-of-way width is standard at 30'. For transmission lines at 69 kV, right-of-way widths vary from 30' to 50'. Transmission lines of 115 kV to 138 kV right-of-way widths vary from 50' to 70'. Transmission lines operating above 138 kV, the right-of-way widths vary from 60' to 180' for 500 kV lines. Growth cycles for transmission lines vary for each company. The average appears to be somewhere around two to four years. This would depend on the type trees in an area and whether trees were fast growing or slower growing trees.

RECOMMENDATIONS

In the Northern JCP&L Region, "non-preventable trees" is listed as the highest (23%) general cause for interruption events and also the highest (34%) general cause for customer minute duration. It is standard practice to reduce the trimming in major urban and metro areas, as well as, historical districts when municipal or other restrictions contribute to the need for more frequent timing. "Non-preventable trees" is a misnomer. Danger trees should be selectively removed when standard pruning and trimming do not remove a hazard. The Board should consider expanding the allowed right-of-way widths by at least 10' and reducing the growth cycle to two years in order to address this major cause of customer outages. Unless Vegetation Management Specifications are changed, the Northern Region will continue to experience significant outages and extended duration of outages from tree-related incidents.

Table 24 below shows the summary of tree trimming expenditure since 1998:

Table 24
Tree Trimming Expenditures

	1998	1999	2000	2001	2002
Northern					
O&M Dollars	$2,782,179	$6,487,239	$7,674,270	$8,691,000	$10,399,823
Capital Dollars	$ 143,818	$ 108,440	$ 11,257	$ 398,134	$ 371,102
Average No. of Crews	*	51	51	67	54
Central					
O&M Dollars	$8,012,278	$4,367,527	$4,852,327	$3,856,466	$ 4,415,679
Capital Dollars	$ 416,955	$ 278,511	$ 27,665	$ 421,034	$ 105,361
Average No. of Crews	*	45	55	37	52
JCP&L					
O&M Dollars	$10,794,457	$10,854,766	$12,526,597	$12,547,466	$14,815,502
Capital Dollars	$ 560,773	$ 386,951	$ 38,992	$ 819,168	$ 476,463
Average No. of Crews	*	96	106	104	106

* *Data not available*

The 2003 plan for tree trimming called for a total of $35,568,000 O&M dollars for the JCP&L system, with $22,600,000 in NNJ Region and $12,888,000 in the CNJ Region. Total number of crews was expected to increase to 180. This 2003 plan includes an incremental $18 million for accelerated tree trimming in an attempt to compress three years of a four-year cycle into two years. As a result, beginning in January 2005, JCP&L will begin a new, regular four-year cycle under FirstEnergy trimming specifications. All tree trimming is done with contractors. JCP&L's Distribution System Assessment for 2002 indicated the trimming contractor normally used by JCP&L went out of business and a new contractor had to be hired. The assessment further stated that historically, it has been challenging for the region to remain on a four-year vegetation trimming cycle while at the same time performing all the requested "hot spot" trimming associated with customer complaints regarding tree-caused outages on circuits that are about to be cycle trimmed.

Paragraph 6 of the MOU, which provides for JCP&L's continued accelerated implementation of the FirstEnergy Vegetation management specifications (which includes a danger or priority tree component) addresses this concern and recommendation.

Wood Pole Maintenance

The wood pole maintenance program in place by GPU, Inc. included inspection of transmission wood poles (46 kV and higher) on a ten-year cycle and inspection of distribution wood poles on a fifteen-year cycle.

During 2002, JCP&L adopted the FirstEnergy (FE) wood pole inspection procedures. The FE practice is to perform ground-line inspections of its transmission and subtransmission wood poles on a fifteen-year cycle. With respect to distribution poles, FE does not have a formally scheduled distribution wood pole inspection program whereby a percentage of the distribution poles are inspected annually. JCP&L has not done any pole inspections in 2002 or 2003 as the policy change provided a two-year window of no action being required under the new FE policy and JCP&L had completed a full cycle of maintenance at the end of 2001 under the GPU policy.

Inspection of 1/15th of the transmission and subtransmission is scheduled for 2004 and will also include a climbing inspection of 10% of the facilities inspected. Based on our interviews, we are uncertain whether JCP&L feels a distribution pole inspection program is ever warranted under the FE policy. If inspections are performed, a group of poles would be identified through various maintenance and data review programs. Given the results of our condition assessment, we recommend that JCP&L return to a fifteen-year cycle of inspection, with 1/15th of the approximately 526,000 wood poles inspected in 2004. The cycle should begin with poles selected from circuits with the worst performing CRI indexes. The pole inspection program should include an action plan. The interviews indicated that inspected poles found to be in need of immediate action, including replacement, were ignored.

Substation Maintenance

Per interviews with JCP&L maintenance staff, a computerized program of tracking maintenance of major pieces of substation equipment was begun about 5 years ago. This program allows for scheduling regular maintenance intervals and tracks the results of the actual work done. Reports can be obtained on each type of equipment that can assist in analysis of maintenance issues amongst identical or nearly identical pieces of equipment. Though maintenance was scheduled regularly through the program, the actual work that was done on a piece of equipment was up to the individual crew's interpretation of the manufacturer's instruction book. This is a clear lack of supervisory control and standard policy and procedure applications. When First Energy bought JCP&L, First Energy was using the same maintenance software along with standardized instructions and checklists for each piece of equipment. These standardized maintenance instructions have been added to the JCP&L maintenance process. Standardized check lists and instructions helps assure that each piece of equipment receives the same level of maintenance regardless of which crew performs the service.

Upon reviewing records in house of power transformers and circuit breakers, it is obvious that good records have been kept that document maintenance (regular examination) of these pieces of equipment. Records are in place that indicates preventive maintenance practices are in effect. Doble, "hot collar", TCG, DGA, and dielectrics on oil testing are all on record. Files were neat and orderly. However, there was no evidence of an electronic database of the power transformer records. However, there was an electronic database for all circuit breaker oil testing. Pre-merger transformer testing was conducted on an annual basis, but post-merger testing is performed on a biennial basis. Once-a-year testing is generally the accepted industry practice. Complete, detailed records of relay reports and calibrations were also filed in a separate cabinet. There is also a serious deficiency with documented test data in the Central Region.

Since the merger with First Energy, management has instituted a standardized maintenance manual. In times prior to the merger, any given lineman would have his own preferred practice of how to perform maintenance on a particular piece of equipment. This process has now been standardized so that maintenance is uniform each and every time. There does exist years of poor practice which clearly means equipment such as transformers are more likely to experience early failure due to a lack of industry standard maintenance.

JCP&L is concluding a program of testing each transformer on their system. In the process of their inspections, they found numerous transformer bushings going bad and proceeded to replace those bushings. We found evidence of this program to be true during the inspections by Booth & Associates, Inc. Many transformer bushings have been replaced. However, efforts toward completing this venture caused other scheduled maintenance to fall behind.

Jersey Central and FirstEnergy appear to have a substation testing program that would be consistent with customary industry practice. FirstEnergy and Jersey Central stated that they perform their inspection and testing program on an annual basis. However, it is important to note that we were unable to find any documentation, and Jersey Central was unable to provide documentation on transformer testing and records documenting transformer testing for the past two to three years, depending on the region. Considering the fact that the FirstEnergy policy is to allow overloading of transformers up to 25% above their nameplate, and considering the fact that there are numerous transformers that are overloaded, it is critical that Jersey Central have a program of annually testing all power transformers. This should not be a program of simply visually inspecting and recording information. This program should include a full complement of Doble testing, turns ratio testing, dissolved gas analysis, and dielectric oil testing as a minimum. Booth is confident that the consistent overloading of transformers above their nameplate value as exhibited by records provided by Jersey Central will result in a significant and more rapid deterioration of transformers and ultimate failure of transformers. This consistent practice of overloading transformers and the policy to allow for the overloading of transformers on a consistent basis of up to 25% above the nameplate value is contrary to all transformer manufacturer recommendations and is contrary to standard and customary utility practice.

As indicated in the Executive Summary, Booth & Associates, together with Board Staff and the Company engaged in an iterative process which made significant progress towards addressing all recommendations and, insofar as the issues discussed above are concerned, to the extent that JCP&L agrees to fully comply with its Asset Management Strategy (AMS) document including the CRI program, which agreement is reflected in the Stipulation of Settlement (which includes the published AMS to which JCP&L has agreed to abide) entered into on June 8, 2004 by JCP&L and Board Staff (and which was reviewed and adopted by the Board), which resolves these concerns.

RECOMMENDATION

It is recommended that JCP&L pursue hiring a larger staff of maintenance mechanics and/or bring in contract maintenance crews to allow regularly scheduled maintenance to proceed at the same time other critical remediation work is underway. It is critical to maintain an aggressive maintenance program, given the aged status of much of the substation equipment, the prior lack of maintenance and testing standards all combined with a history of equipment abuse through periodic summer overloading. It is not possible to accomplish all the required tasks at hand with the manpower in place. In order to maintain good maintenance practices while upgrading and revamping their electric system, expanding substation maintenance and testing staff together with trained inspectors/supervisors will be necessary.

We strongly recommend that Jersey Central and FirstEnergy perform the full complement of tests on every transformer on an annual basis which has seen a peak load in the prior year equal to or above the nameplate rating of the transformer, even if such loading has only occurred for one hour. We also strongly recommend that all transformers receive a full complement of tests, not simply visual inspection, at least once every two years. These steps should include but are not necessarily limited to a Doble test, the dissolved gas analysis, turns ratio test, dielectric oil test, and power factor test.

As indicated in the Executive Summary, Booth & Associates, together with Board Staff and the Company engaged in an iterative process which made significant progress towards addressing all recommendations and, insofar as the issues discussed above are concerned, to the extent that JCP&L agrees to fully comply with its Asset Management Strategy (AMS) document including the CRI program, which agreement is reflected in the Stipulation of Settlement (which includes the published AMS to which JCP&L has agreed to abide) entered into on June 8, 2004 by JCP&L and Board Staff (and which was reviewed and adopted by the Board), which resolves these recommendations.

FirstEnergy Planning Criteria

The following is a review of the GPU Energy Transmission and Distribution System Planning Criteria that was used by JCP&L from the time it became a GPU Company until First Energy released its planning criteria in March of 2002. The following discussion will include and compare the planning criteria of both GPU and First Energy. Only local transmission (sub transmission) and distribution will be covered under this discussion.

Local transmission is generally the 34.5 kV system with some 115 kV line that is not involved in bulk transmission.

The GPU criteria states that transmission circuits will be rated based on ambient temperatures at 35º Celsius in summer and 10º Celsius in winter using the PJM guidelines. Where the PJM thermal rating is not applicable, standard engineering approximation will be used to determine which thermal rating methodology is appropriate. Local transmission systems rated at 35 kV will have a maximum current rating of 870 amps for normal current and 1005 amps for emergency current limits. New circuits constructed with ACSR conductor will normally be designed at 125ºC. New circuits constructed with ACAR will be designed to be rated at 100º C.

For the distribution system the overhead conductor normal and emergency rating should be based on an ambient temperature at 35ºC for summer and 10º C for winter. Underground cable normal and emergency ratings should be based on 90ºC operating temperature and 75% load factor. For distribution feeders, the maximum normal loading of any distribution circuit 15 kV or below shall be the lesser of the normal seasonal rating, 450 amperes or 75% of the emergency rating of the conductor.

The following line ratings are from the First Energy Planning Analysis Handbook. The local transmission (sub transmission) according to Paragraph 3.1 is to be rated for normal loading using an ambient temperature of 35ºdegrees C in the summer and 0º C in the winter with appropriate seasonal wind speeds. Emergency ratings are to be developed using an ambient of 32º C in the summers and 0ºC in the winter, again, with appropriate wind speeds. According to Attachment 2 the ambient temperature for emergency ratings has been decreased to 30ºC ambient for local transmission summer ratings. Returning to Paragraph 3.1, new and rebuilt overhead local transmission circuits constructed with ACSR conductors will be built to operate at 125ºC for both normal and emergency conditions. Overhead circuits for copper or aluminum may be rated to operate at 80º C for normal conditions and 100º C for emergency conditions.

In Paragraph 3.2 distribution the summer operating temperatures are again 35ºC in the summer and 0º C in the winter. This will be used for rating the conductor. New or rebuilt overhead distribution circuits are built with ACSR or AA conductor and designed to operate at 93.3º C. This is equivalent to 200º Fahrenheit. Older ACSR circuits were built to operate at 80º C and should be rated to operate at that temperature. It states that if the operating temperature becomes a limiting facility field, investigations may be performed to determine if the circuit has clearance to operate at 93.3º C. According to this planning criterion, the ambient temperature for distribution conductor for summer is 35ºC for normal conditions and 32ºC for emergency conditions. The summer wind speed for distribution conductor is 2.1 miles per hour for normal conditions and 4.3 miles per hour for emergency conditions. As stated before, the design temperature for older distribution line is 80º C and newer distribution line is 93.3ºC.

The ratings for local transmission are similar to that of distribution except that new design temperature is 125º C and in Attachment 2 the wind speed for emergency ratings has been increased to 4.4 feet per second wind and 30º C ambient.

The following discusses the local transmission system testing requirements under the GPU planning criteria. Under peak load conditions the loss of any single major component including transmission line or transformer will not cause loadings to exceed the seasonal 15 minute emergency rating of any transmission facility. After the occurrence of an outage described above and the subsequent isolation of the failed equipment, the system must be capable of operation without exceeding the 4 hour emergency rating of any transmission facility. After the occurrence of the outage described above and following completion of all applicable system adjustments, the system must be capable of operation without exceeding the 24 hour emergency rating of any transmission and facility failures that require less than 24 hours to repair such as transmission lines. The 6 month emergency rating would be applied to transmission facilities for failures that require more than 24 hours to repair such as transformers.

Under distribution first contingency operations the emergency loading of any component of the distribution feeder should not exceed the emergency seasonal rating. It also states that underground substation always should be sized to match the thermal capability of the overhead conductor when practical. Under distribution substations the GPU criteria states that the maximum normal rating of a distribution substation transformer should be the normal seasonal rating. The emergency loading of a distribution substation transformer should not exceed the 24 hour emergency rating for short term outages. The emergency loading should not exceed the 1 week emergency rating for long term transformer outage if an applicable spare transformer is available within the system. Emergency loading should not exceed the 6 month emergency rating for long term transformer outage if there are no spare transformers available within the system. Under service interruptions in the GPU Criteria, the following is stated. "The system will be planned in such a manner that under first contingency outage conditions on any distribution circuit and at any distribution voltage after all available switching has occurred up to 6 MVA load may remain interrupted until necessary repairs are completed." The following sub paragraph states, "large amounts of load may remain interrupted in some circumstances such as circuits to primarily one customer." The third paragraph or section states, "under distribution substation transformer or both outage condition and after all available switching has occurred up to 10 MVA load may remain interrupted until a mobile transformer unit is installed."

The following discusses the local transmission system testing requirements under the First Energy Planning Criteria. Under Paragraph 5.1, Normal Loading Analysis, the criteria state, "a 50/50 seasonal peak load forecast with appropriate load diversity should be used for local transmission operating studies and for local transmission planning studies." A 50/50 seasonal peak is the projected peak such that there is a 50% chance that the actual peak will exceed the 50/50 peak and a 50% chance that the actual peak will be less than the 50/50 peak. It appears that this is essentially an average projection based on normal conditions with the possibility that unusual weather or other conditions would result in greater or lesser peaks. It is stated that at the discretion of First Energy management, a 90/10 forecast or other maximum credible heat storm forecast may be used to develop short term load relief plans under normal system operation (all equipment in service) for identified critical areas (i.e. coastal areas of central New Jersey).

Under first contingency analysis Paragraph 5.2.1 Contingency Loading, states in the first sub paragraph that faults that result in automatic isolation of the faulted element should not result in loadings greater than the 1-hour rating of any local transmission element. The second paragraph states that at the occurrence of an outage listed above and after the operation of any automatic or supervisory switches, loading should not exceed the 4-hour rating of any local transmission element. The third paragraph states that after the occurrence of an outage listed above and following the completion of all available system adjustments including manual switching operations, the system must be capable of operation without exceeding the 24 hour emergency rating of any transmission element for failures that require less than 24 hours to repair such as transmission lines. The 6 month emergency rating will be applied to transmission facilities for failures that typically require more than 24 hours to repair such as transformers. At the discretion of First Energy management a 1 or 2 week transformer rating may be used during a local transformer failure if a suitable spare transformer is available and on site.

Paragraph 5.2.2 is entitled, "Open Ended Local Transmission Line Contingency". This states that contingencies that result in open ended local transmission line should be performed at an operating load level that is not exceeded more than 100 hours per year. This load level is approximately 85% for New Jersey. By accepting the risk that First Energy may not be able to restore supply if an outage occurs during the 100 highest load hours of the year, the load level can be reduced to approximately 85 to 90% of the projected peak for an open ended local transmission line contingency.

The following discusses distribution system testing requirements. Under Paragraph 6.2, First Contingency Analysis, the First Energy Criteria states that the faults that result in the loss of a distribution transformer should not result in loadings greater than the 1 hour rating of any local transmission element after automatic isolation or faulted element. After the occurrence of an outage listed above and after the operation of any automatic supervisory or manual switches, the amount of load left out of service should not exceed the rating of the largest available mobile transformer. At voltages where there is no available mobile (230 – 13.2 kV), all load must be restored through switching. A detailed review of the substation under study should be performed to verify that a mobile can be installed in a 24 hour period.

Conclusions

It appears that the biggest difference between the GPU Planning Criteria and the current First Energy Criteria is the maximum allowable loadings on both subtransmission and distribution conductor for emergency conditions and in some cases for normal conditions. For example, under the GPU Planning Criteria for distribution systems, the maximum normal loading of any distribution circuit (15 kV or less) was the lesser of 450 amperes or 75% of the emergency rating of the conductor. Under the First Energy Criteria, 397.5 ACSR has a rating of 697 amperes, and 556.5 ACSR has a rating of 888 amperes. Under GPU, the ambient temperature used to determine the normal and emergency ratings for both distribution and transmission was 35º C for summer. Under First Energy, the ambient temperature for rating local transmission during emergency conditions was initially 32º C and then was reduced to 30º C ambient. Also, the First Energy Planning Criteria initially used 3 feet/second wind speed for calculating emergency ratings of conductor, and has since increased that to 4.4 feet/second.

The end result of this increase in conductor ratings is as follows: for normal conditions, the 450 amperes maximum normal loading used for distribution circuits under GPU equated to approximately 9,700 kW on a 12.5 kV distribution circuit. The 650 or more amps allowed on newer conductors of 336.4 ACSR or larger on new circuits equates to over 14,000 kW per circuit. This is an increase of approximately 44%.

Table 25

Transmission at 125º C Design Normal Ratings 336 ACSR	
Ambient temp – Degree F	95
Ambient temp – Degree C	35
Conductor temp – Degree C	125
Wind – feet/second	3.1
Amperes	790

Table 26

Transmission at 125º C Design Emergency Ratings 336 ACSR	
Ambient temp – Degree F	86
Ambient temp – Degree C	30
Conductor temp – Degree C	125
Wind – feet/second	4.3
Amperes	874

It can be seen from Tables 25 and 26, by artificially reducing the ambient temperature from 35º C to 30º C, or from 95º F to 86º F, and increasing the wind speed from 3.1 feet/second to 4.3 feet per second, the ampacity of the 336 ACSR conductor designed for operation at 125º C increases from 790 amperes to 874 amperes for a total increase of approximately 11% in capacity. Based on annual climatological summaries for reporting stations in each of the two regions from 1999 through 2002, the following was noted. Each summer, there is at least one month during which the temperature exceeds 100º F, and on the average, there are at least 25 days each year during which the temperature exceeds 90º F.

It should be noted that two other items stand out in the First Energy Planning Criteria. Local transmission planning is typically based on a 50/50 seasonal peak which is equivalent to an average projected peak. There is a discretion using a 90/10 forecast under certain conditions. This equates to a projected peak with only a 10% chance of the actual peak exceeding the projected peak. Another item is the open-ended local transmission line contingency. Contingencies that result in an open-ended local transmission line should perform an operating load level that is not exceeded more than 100 hours per year. This loaded level is approximately 85% for New Jersey. The final item in the First Energy Study is that it allows load to be out of service during emergencies as long as the load can be restored within a 24-hour period by installing a mobile transformer.

The various items discussed so far, along with the other items in this report, give a clear indication that JCP&L is continually increasing the amount of load that can be served with existing facilities. Although this does delay the capital expenditures for installing new facilities there are consequences. Increasing the wind speed for emergency rating conductors and decreasing the ambient temperature would be acceptable for those times when the temperature and wind speeds are actually at those levels used for rating conductors. However, when temperatures climb above those levels and wind speeds drop below those levels, then service conditions deteriorate. Some of the consequences are reduced service voltage to customers, reduced clearance levels resulting in potential safety hazards, overheating and loss of service life for existing conductors and other equipment, etc. Even more of a concern is the increased allowable normal summer ratings for a conductor. The results of increasing the conductor to ratings of 650 amperes or more can result in conductors have the following consequences. If one feeder is carrying 14 MW or more of load and the breaker for that feeder opens due to a fault on the line, then 14 MW of load is lost until service can be restored to that line. Under the GPU Criteria, a maximum of 9,700 kW of load was allowed on a line for normal conditions which reduced the number of customers suggested to outages during breaker operations to 2/3 that of the First Energy Criteria. The other problem with rating distribution conductors at such high levels is that there is little or no spare capacity for servicing customers during emergencies. If a distribution feeder is already operating near its absolute maximum capacity, and that line is outaged near the beginning of the feeder, how can that load possibly be shifted to other feeders in that station (or surrounding stations) if all the feeders are loaded at or near the maximum capacity. Even if the surrounding feeders aren't loaded to the maximum capacity, but near it with some spare capacity, can these circuits even pick up the load due to voltage constraints? It is doubtful that any of these circuits can pick up any substantial additional load due to voltage constraints. Transmission planning open-ended local transmission line contingency is based on operating load levels that are not exceeded more than 100 hours per year. As stated in the First Energy Planning Criteria, "by accepting the risk that First Energy may not be able to restore supply if an outage occurs to the 100 highest load hours of the year, the load level can be reduced to approximately 85–90% of the projected peak from open-ended local transmission line contingency." Unfortunately, it is not First Energy alone that is accepting the risk that supply may not be restored, but also the customers of First Energy are accepting that same risk. The same objections that apply to loading distribution circuits to extreme levels also apply to the local transmission system. When the Summer Operating Studies for the last five years were reviewed, it was apparent that the auto-load transfer schemes for over 80 substations had to be disabled each summer in order to avoid overloading of system components during first contingency conditions. Again, this is the direct result of pushing conductor loading to extremes during normal conditions, and even more so during emergency conditions. As noted in more detail in other parts of the report, substation transformers are also loaded to their maximum nameplate level and beyond for normal operations during summer months. As noted in the First Energy Planning Criteria, outages due to transformer losses of up to 24 hours are acceptable while a mobile is being imported and installed. Again, if transformers are loaded to much lower levels for maximum normal operations, this would provide spare capacity which could be used to serve load if a substation transformer fails.

Although contingency planning studies are performed at the subtransmission level, they are rarely performed for the distribution system. Occasionally, contingency studies will be prepared for critical loads such as hospitals.

As indicated in the Executive Summary, Booth & Associates, together with Board Staff and the Company engaged in an iterative process which made significant progress towards addressing all recommendations and, insofar as the issues discussed above are concerned, to the extent that JCP&L agrees to fully comply with its Asset Management Strategy (AMS) document including the CRI program, which agreement is reflected in the Stipulation of Settlement (which includes the published AMS to which JCP&L has agreed to abide) entered into on June 8, 2004 by JCP&L and Board Staff (and which was reviewed and adopted by the Board), which resolves these concerns.

RECOMMENDATIONS

- For overhead distribution conductor, both emergency and normal ratings should be based on 35 degrees C ambient temperature, 2 feet per second wind speed and full sun. The line should be operated at 70 degrees C maximum for normal conditions and 93.3 degrees C for emergency conditions or the maximum design temperature of the line if less than 93.3 degrees C. The following is a sample of conductor ratings under the recommended criteria compared to the FirstEnergy rating.

Table 27
Recommended Distribution Conductor Ratings

Conductor	Recommended Normal Rating Amps	FE Criteria Amps	Recommended Emergency Rating Amps	FE Criteria Amps
336.4 ACSR	417	559	573	643
556.5 ACSR	565	770	786	888
795 ACSR	707	966	995	1,119
397.5 AAC	450	605	618	706
556.5 AAC	553	744	766	857

As indicated in the Executive Summary, Booth & Associates, together with Board Staff and the Company engaged in an iterative process which made significant progress towards addressing all recommendations and, insofar as the issues discussed above are concerned, to the extent that JCP&L agrees to fully comply with its Asset Management Strategy (AMS) document including the CRI program, which agreement is reflected in the Stipulation of Settlement (which includes the published AMS to which JCP&L has agreed to abide) entered into on

June 8, 2004 by JCP&L and Board Staff (and which was reviewed and adopted by the Board), which resolves this recommendation.

- For local-transmission conductor, both emergency and normal ratings should be based on 35 degrees C ambient temperature, 2 feet per second wind speed and full sun. The line should be operated at 70 degrees C maximum for normal conditions and 100 degrees C for emergency conditions or the maximum design temperature of the line if less than 100 degrees C. The following is a sample of conductor ratings under the recommended criteria compared to the FirstEnergy rating.

Table 28
Recommended Local Transmission Conductor Ratings

Conductor	Recommended Normal Rating Amps	FE Criteria Amps	Recommended Emergency Rating Amps	FE Criteria Amps
336.4 ACSR	417	657	609	754
556.5 ACSR	565	927	836	1,042
795 ACSR	707	1,156	1061	1,312

As indicated in the Executive Summary, Booth & Associates, together with Board Staff and the Company engaged in an iterative process which made significant progress towards addressing all recommendations and, insofar as the issues discussed above are concerned, to the extent that JCP&L agrees to fully comply with its Asset Management Strategy (AMS) document including the CRI program, which agreement is reflected in the Stipulation of Settlement (which includes the published AMS to which JCP&L has agreed to abide) entered into on June 8, 2004 by JCP&L and Board Staff (and which was reviewed and adopted by the Board), which resolves this recommendation.

- Distribution planning studies should be prepared each year. These studies should be based on three or more years of projected growth. The projections should be the 90/10 projections rather the 50/50 projections. Improvements dictated by the plan should be implemented prior to the summer peak each year rather than in response to the previous summer peak.

As indicated in the Executive Summary, Booth & Associates, together with Board Staff and the Company engaged in an iterative process which made significant progress towards addressing all recommendations and, insofar as the issues discussed above are concerned, to the extent that JCP&L agrees to fully comply with its Asset Management Strategy (AMS) document including the CRI program, which agreement is reflected in the Stipulation of Settlement (which includes the published AMS to which JCP&L has agreed to abide) entered into on June 8, 2004 by JCP&L and Board Staff (and which was reviewed and adopted by the Board), which resolves this recommendation.

- In conjunction with the recommended distribution planning studies, a distribution contingency study should be prepared for the entire distribution system. Although it may not be feasible to provide contingency backup service to all feeders, it should be the goal of JCP&L to provide backup from same sub feeders or from other sub feeders for most circuits. Along with feeder contingency, distribution substation transformers should be loaded such that other transformers in the same substation or in adjacent substations can serve the load if any single transformer fails. This should be achieved without exceeding the maximum nameplate rating of any transformer.

As indicated in the Executive Summary, Booth & Associates, together with Board Staff and the Company engaged in an iterative process which made significant progress towards addressing all recommendations and, insofar as the issues discussed above are concerned, to the extent that JCP&L agrees to fully comply with its Asset Management Strategy (AMS) document including the CRI program, which agreement is reflected in the Stipulation of Settlement (which includes the published AMS to which JCP&L has agreed to abide) entered into on June 8, 2004 by JCP&L and Board Staff (and which was reviewed and adopted by the Board), which resolves this recommendation.

- Other recommendations that pertain only to subtransmission are included in the review of Summer Operating Studies.

As indicated in the Executive Summary, Booth & Associates, together with Board Staff and the Company engaged in an iterative process which made significant progress towards addressing all recommendations and, insofar as the issues discussed above are concerned, to the extent that JCP&L agrees to fully comply with its Asset Management Strategy (AMS) document including the CRI program, which agreement is reflected in the Stipulation of Settlement (which includes the published AMS to which JCP&L has agreed to abide) entered into on June 8, 2004 by JCP&L and Board Staff (and which was reviewed and adopted by the Board), which resolves this recommendation.

T&D Construction Standards

Our review of the FirstEnergy T&D Construction Standards revealed three major areas of concern:

1. Pole top extension – use of pole top extensions is not limited and the effect of pole loading caused by the extension is not incorporated into the design criteria. Our condition assessment revealed many examples of

improper pole extensions which can lead to reliability problems. In general, use of pole top extensions will rarely meet NESC for proper loading; therefore, industry-wide convention is to replace poles with properly classed and sized poles rather than use pole top extensions.

2. Use of "spacer cable" construction should be limited only for use in areas where right-of-way clearing cannot be implemented. General use should not be allowed.

3. Grounding of guys is not required. We feel this is a safety issue that requires change.

During our interviews we attempted to determine if special material standards are used in coastal areas because of the saltwater environment. We were told that the special condition was taken into account during design and construction.

Accelerated Reliability Improvement Plan (ARIP)

The ARIP is JCP&L's answer to improve reliability within a short time frame in the two Regions. The program was initiated February 2003 and included ten major projects funded at more than $50 million. Our analysis indicates that the tree trimming program was a positive step. So was the work developed to correct the Barrier Peninsula feeder damage which occurred. All the other projects appear to be facilities and equipment for monitoring and accountability, but nothing addressing the real issue – which is the necessity to upgrade the degraded distribution system. Projects included in ARIP such as feeder protection reviews, substation transformer protection, 34.5 kV coordinating and automation are standard customary utility practices. GIS field audit and purchase of mobile capacitor banks have little to do with addressing the real problem. Although acknowledged to be accelerated, all these projects are normal operating and maintenance programs that well-run utilities throughout the U.S. maintain and implement daily in order to remain on the leading edge of technology. Circuits being unfused to the extent we have observed and lack of recloser and sectionalizing are not consistent with generally accepted utility practice.

JCP&L compliments itself on its Accelerated Reliability Improvement Plan and includes in its rebuttal of the Booth January 9, 2004 Executive Summary, using statements that it has installed 1,013 fuses and 139 reclosers. This is a minimal good first step. Considering that Jersey Central has 1,108 circuits, this is an addition of approximately one fuse per circuit, which is minimalistic at best. The addition of 139 reclosers, although a good start considering the significant deficiency in system protective coordination equipment including reclosers, is only approximately one recloser for every ten circuits. Jersey Central has 1,000 circuits that need significant protective coordination evaluation and implementation of improved programs, not just on an Accelerated Reliability Improvement Plan basis. More importantly, on a long-term basis JCP&L must make significant improvements in protective coordination and addition of reclosers and fuses each and every year.

The FirstEnergy executives we interviewed described their design philosophy, which was also stated in their Distribution System Assessment documents –

> "The design philosophy of the FirstEnergy Corporation, since 1993, has been built around the full utilization of thermal capacity in equipment and overhead conductors. This full utilization, and building for actual (not perspective) load requirements, has been made possible by the implementation of enhanced radial circuit tie capability and the modular designed substation. This modular station (10/12MVA, 2-exit) utilizes standard material/equipment and simplified construction/design which shorten the in-service time frame and has enabled the meeting of load requirements as they have presented themselves."

When this design philosophy is superimposed on a system such as JCP&L's, which has not been well maintained, a formula for disaster is in place. The results of our review of the new planning and construction standards as discussed above result in the requirement that existing transformers and conductors must carry additional loads, further stressing an already overloaded and stressed distribution system.

Paragraph 4 of the MOU, which provides, among other things, for JCP&L's continued fusing of certain circuit lateral taps and certain main feeder sectionalizing consistent with JCP&L's circuit protection philosophy, resolves this recommendation. Also, as indicated in the Executive Summary, Booth & Associates, together with Board Staff and the Company engaged in an iterative process which made significant progress towards addressing all recommendations and, insofar as the issues discussed above are concerned, to the extent that JCP&L agrees to fully comply with its Asset Management Strategy (AMS) document including the CRI program, which agreement is reflected in the Stipulation of Settlement (which includes the published AMS to which JCP&L has agreed to abide) entered into on June 8, 2004 by JCP&L and Board Staff (and which was reviewed and adopted by the Board), which resolves this recommendation.

8. System Reliability and Contingency Planning

Review of System Reliability History for JCP&L

Interim Electric Distribution Service Reliability and Quality Standards were adopted by the Board on January 2, 2001. Under the Interim Standards each electric utility is required to prepare an Annual System Performance Report by May 31 of each year, reporting results from the previous calendar year. The rules readopted by the Board on August 21, 2002 do not require the filing of annual system performance reports beyond September 1, 2002. It is our recommendation that JCP&L continue to file an annual report, as long as, reliability standards are not met. Note, as discussed below, we feel the ten-year historic averages for CAIDI and SAIFI are not the appropriate benchmark for reliability and offer objective performance standards based on a combination of System Overall and System Component Performance Standards.

Our analysis of the system reliability history for Jersey Central Power & Light (JCP&L) was based on two data sources. The first source for reliability history and indexes is the 2002 Annual System Performance Report prepared by JCP&L. The second source is based on individual outage reports for 1998 through 2002 provided in electronic format by JCP&L.

As noted in the System Performance Report, the system as per Board requirements uses a ten year historic average as the benchmark for comparison of current reliability indexes. The ten year period in this report was based on the 1990-1999 average. Of note is the fact that from 1990 through 1997 the indexes included major events[1] such as, major storms. Beginning in 1998 JCP&L began to exclude major storm events in their calculation of reliability indexes. JCP&L also installed an outage management system (OMS) in December 1999. These two instances tend to affect the comparison of the historic indexes versus current indexes for the following reasons. The OMS System installed in 1999 provided for more accurate reporting of outages. Based on the installation of such systems at other utility systems, the typical result is that outage indexes tend to increase as a result of outages being reported and recorded that may have been missed prior to the installation of an OMS. On the other hand, the fact that the benchmark included eight years during which major events were included in covering indexes would result in a benchmark which is high compared to current indexes which do not

[1] Historically, a major event has been defined as an incident that resulted in more than 65,000 customers without power for more than 24 hours. The Interim Electric Distribution Service Reliability and Quality Standards currently define a major event in part as a sustained interruption of electric service resulting from conditions beyond the control of the Electric Distribution Company which may include, but is not limited to, thunderstorms, tornadoes, hurricanes, heat waves or snow and ice storms which affect at least 10% of the customers in an operating area.

include major events. The end result is that the deletion of major events in recent years from reliability indexes and the installation of the OMS system in 1999 result in a benchmark which can not be directly related to current outage indexes. As time progresses and the average ten year period includes more and more years in which major events are excluded and the OMS system has been installed, this inaccuracy will decrease and eventually be eliminated.

Table 29
JCP&L Reliability Metrics
1999-2002

	Customer Average Interruption Duration Index **CAIDI**	**System Average Interruption Duration Index** **SAIDI**	**Customer Average Interruption Frequency Index** **SAIFI**
1999	2.55	1.68	.66
2000	4.42	9.78	2.22
2001	2.36	2.44	1.03
2002	2.59	3.06	1.18
Ten Year Average	2.53	- -	0.97

It can be seen in Table 29 that for each of the three categories the highest indexes occurred in the year 2000. The reason for this is not clear according to the report, which of course focuses mainly on the year 2002. When looking at the list of all outages for 2002, 2.2 million consumer hours of the total 4.8 million consumer hours were due to one cause. This cause was unknown. Returning to the 2002 Annual System Performance Report and excluding the year 2000, the indexes in 2002 were higher than those in 1999 and 2001. Also, the indexes for 2002 were slightly higher than the ten year average.

As indicated earlier however, it is difficult to compare the current indexes with the ten-year historic averages due to the OMS program to a small degree, and more importantly, the elimination of major events. A major event is certainly important to the customer and should be a consideration. The elimination of major events provides a skewed picture of potential improvement. Each of the three indexes can be interpreted as follows. A CAIDI of 2.59 for 2002 indicates that for each customer who experienced one outage or more per year, the average length of each outage was 2.59 hours. The SAIFI indicates the average number of outages per customer throughout the system. For 2002 each customer, on average, experienced 1.18 outages. The SAIDI indicates the average outage time per all customers for the year. For 2002 the average per all customers is 3.0 hours of outage time. The CAIDI or average time per each customer affected was 2.59 hours and the SAIDI or average time for all customers was 3.06 hours. The reason that the CAIDI is less than the SAIDI would indicate that a number of customers subjected to outages experienced two or more outages each.

Table 30
Reliability Metrics IEEE Survey

IEEE Survey of U.S. Utilities									
Quartile	**CAIDI**			**SAIDI**			**SAIFI**		
	1990	**1995**	**AVG**	**1990**	**1995**	**AVG**	**1990**	**1995**	**AVG**
1	.818	.911	.864	1.109	.894	1.00	1.09	.90	1.00
2	1.309	1.306	1.30	1.588	1.50	1.54	1.40	1.10	1.25
3	1.647	1.799	1.72	2.028	2.304	2.16	1.71	1.45	1.58
4	3.083	3.290	3.18	4.085	7.05	5.56	3.30	3.90	3.60
Overall Average	**1.346**	**1.471**	**1.41**	**1.651**	**1.947**	**1.80**	**1.49**	**1.26**	**1.38**

The IEEE Power Engineering Society Working Group on System Design surveyed a number of utilities in the United States in 1990 and 1995 to determine their reliability practices and reliability indexes. As can be seen from Table 30, both the 2002 CAIDI and SAIDI for JCP&L are in the fourth quartile, meaning they are in the worst performing quarter of the responding utilities. The only index which is not in the fourth quartile is SAIFI, which is in the second quartile. The comparison of JCP&L indexes to the IEEE Survey indexes would tend to indicate that the average number of interruptions per consumer is below that of 50% of the responding utilities in the survey, but the duration of outages is in the worst 25% of the responding utilities in the Survey. This of course could appear better than it really is since JCP&L eliminates major storm events with a definition that distorts the reality.

Table 31
NJ – Entire System Outages 1999-2002

NJ - Entire System Outages 1999 - 2002				
Cause	Customer Minutes	Customer Hours	Customers Affected	%
Unknown	227,232,378	3,787,206	1,577,373	29.9%
Trees - Non Preventable	92,831,309	1,547,188	421,739	12.2%
Electrical Failure	83,687,274	1,394,788	428,870	11.0%
Animal contact	71,602,764	1,193,379	628,629	9.4%
Corrosion / Deterioration	41,153,173	685,886	207,010	5.4%
Vehicle	40,529,784	675,496	219,937	5.3%
Mechanical Failure	35,340,635	589,011	197,254	4.6%
Other (Specify)	34,766,784	579,446	149,772	4.6%
Loss of Supply	28,096,287	468,271	144,757	3.7%
Trees - Preventable	27,928,194	465,470	146,034	3.7%
Burned/Fire	16,066,166	267,769	127,052	2.1%
OPER COND	14,899,960	248,333	83,175	2.0%
Operations related	10,179,540	169,659	74,463	1.3%
DETERIORATION	8,694,791	144,913	53,276	1.1%
Foreign Object	7,201,537	120,026	28,065	0.9%
EQUIP FAIL-EL	3,364,204	56,070	32,371	0.4%
CABLE DIG-IN	3,126,557	52,109	15,395	0.4%
Customer problem	2,449,079	40,818	12,601	0.3%
EQUIP FAIL-ME	2,222,279	37,038	9,790	0.3%
Electrical Overload caused by customer	1,661,019	27,684	9,602	0.2%
Vandalism	1,247,388	20,790	6,700	0.2%
Error- GPUE employee	855,348	14,256	18,684	0.1%
LIGHTNING	764,949	12,749	2,617	0.1%
Foreign Utility Contact	606,536	10,109	6,690	0.1%
Deterioration of wood due to insects	606,426	10,107	1,897	0.1%
Customer Contact	513,037	8,551	4,429	0.1%
Error- Contractor	482,202	8,037	7,234	0.1%
Deterioration of wood due to age	461,194	7,687	2,321	0.1%
Insulator Contamination	423,241	7,054	1,743	0.1%
Call-Error	281,872	4,698	1,965	0.0%
Planned Outage	255,199	4,253	7,840	0.0%
Deter of wood due to adverse site cond	218,526	3,642	813	0.0%
FOREIGN OBJ	209,884	3,498	844	0.0%
MAINT/TEST	60,448	1,007	641	0.0%
Flooding	55,972	933	78	0.0%
ERROR-COMP	52,843	881	548	0.0%
COVER EL FAC	39,672	661	808	0.0%
REQUEST	30,820	514	313	0.0%
FOREIGN UTIL	17,336	289	203	0.0%
CUSTOMER EQUIPMENT	12,092	202	83	0.0%
ERROR-CONTR	9,734	162	171	0.0%
CONTAMINATION	5,044	84	8	0.0%
TREE-SVC WIRE	2,628	44	14	0.0%
Salt Contamination	2,167	36	11	0.0%
Deterioration of wood due to birds	703	12	13	0.0%
Outage Total:	**760,248,975**	**12,670,816**	**4,633,833**	

Table 31 shows a summary of information of the individual distribution outages for the system from 1999 until 2002. As indicated, these outages are based on outages in the distribution system.

One factor that skews the outages by cause is the fact that in the year 2000, the consumer hours due to unknown causes was over 2.2 million hours. The other three years, the consumer hours due to unknown causes ranged from 366,000 to 672,000. In excess of 2.2 million consumer hours in 2002 is an enormously high number of hours to be attributed to unknown causes. This would appear to indicate one of three possibilities: (1) there was one major event for which the cause was unknown; (2) there were a number of smaller events for which either the cause is unknown or the cause is listed as unknown due to confusion or a lack of knowledge of those listing the causes, or (3) JCP&L has a systemic outage reporting deficiency.

We think there is a serious reporting problem as relates to outages due to lightning. Other electric utilities in the Northeast typically experience lightning related outages on the order of ten to a hundred times that of JCP&L. We strongly suspect that much of the outages due to unknown causes along with other causes such as electrical failure were due to lightning. Installation of additional lightning arresters, reduction of ground rod resistance and replacement of older arresters with MOV arresters will reduce outages due to lightning. Ground rod resistance can be reduced by increasing the total length of ground rods (i.e., use sectional ground rods) driving additional ground rods (distance between rods should be no less than maximum depth of any one rod) and use of special fillers (such as bentonite). Lowering ground rod resistance will not only reduce lightning related outages but will also improve other problems such as stray voltage.

As indicated in the Executive Summary, Booth & Associates, together with Board Staff and the Company engaged in an iterative process which made significant progress towards addressing all recommendations and, insofar as the issues discussed above are concerned, to the extent that JCP&L agrees to fully comply with its Asset Management Strategy (AMS) document including the CRI program, which agreement is reflected in the Stipulation of Settlement (which includes the published AMS to which JCP&L has agreed to abide) entered into on June 8, 2004 by JCP&L and Board Staff (and which was reviewed and adopted by the Board), which resolves this concern and recommendation.

Table 32
JCP&L Outages Reclassified

NJ - Entire System Outages 1999 - 2002

Other/Unknown			% of total:	34.5%
Cause	Customer Minutes	Customer Hours	Customers Affected	Percent of Total
Unknown	227,232,378	3,787,206	1,577,373	29.9%
Other (Specify)	34,766,784	579,446	149,772	4.6%
Total:	261,999,162	4,366,653	1,727,145	34.5%

Preventable			% of total:	32.6%
Cause	Customer Minutes	Customer Hours	Customers Affected	Percent of Total
Electrical Failure	83,687,274	1,394,788	428,870	11.0%
Animal contact	71,602,764	1,193,379	628,629	9.4%
Corrosion / Deterioration	41,153,173	685,886	207,010	5.4%
Mechanical Failure	35,340,635	589,011	197,254	4.6%
DETERIORATION	8,694,791	144,913	53,276	1.1%
EQUIP FAIL-EL	3,364,204	56,070	32,371	0.4%
EQUIP FAIL-ME	2,222,279	37,038	9,790	0.3%
Deterioration of wood due to insects	606,426	10,107	1,897	0.1%
Deterioration of wood due to age	461,194	7,687	2,321	0.1%
Insulator Contamination	423,241	7,054	1,743	0.1%
Deter of wood due to adverse site cond	218,526	3,642	813	0.0%
CONTAMINATION	5,044	84	8	0.0%
Deterioration of wood due to birds	703	12	13	0.0%
Total:	247,780,254	4,129,671	1,563,995	32.6%

Trees			% of total:	15.9%
Cause	Customer Minutes	Customer Hours	Customers Affected	Percent of Total
Trees - Non Preventable	92,831,309	1,547,188	421,739	12.2%
Trees - Preventable	27,928,194	465,470	146,034	3.7%
Total:	120,759,503	2,012,658	567,773	15.9%

Non-Preventable			% of total:	9.7%
Cause	Customer Minutes	Customer Hours	Customers Affected	Percent of Total
Vehicle	40,529,784	675,496	219,937	5.3%
Burned/Fire	16,066,166	267,769	127,052	2.1%
Foreign Object	7,201,537	120,026	28,065	0.9%
CABLE DIG-IN	3,126,557	52,109	15,395	0.4%
Customer problem	2,449,079	40,818	12,601	0.3%
Electrical Overload caused by customer	1,661,019	27,684	9,602	0.2%
Vandalism	1,247,388	20,790	6,700	0.2%
Foreign Utility Contact	606,536	10,109	6,690	0.1%
Customer Contact	513,037	8,551	4,429	0.1%
FOREIGN OBJ	209,884	3,498	844	0.0%
COVER EL FAC	39,672	661	808	0.0%
REQUEST	30,820	514	313	0.0%
FOREIGN UTIL	17,336	289	203	0.0%
CUSTOMER EQUIPMENT	12,092	202	83	0.0%
TREE-SVC WIRE	2,628	44	14	0.0%
Total:	73,713,535	1,228,559	432,736	9.7%

Table 32 (continued)

Operations Related			% of total:	3.3%
Cause	**Customer Minutes**	**Customer Hours**	**Customers Affected**	**Percent of Total**
OPER COND	14,899,960	248,333	83,175	2.0%
Operations related	10,179,540	169,659	74,463	1.3%
Planned Outage	255,199	4,253	7,840	0.0%
MAINT/TEST	60,448	1,007	641	0.0%
Total:	25,395,147	423,252	166,119	3.3%

Loss of Supply			% of total:	1.3%
Cause	**Customer Minutes**	**Customer Hours**	**Customers Affected**	**Percent of Total**
Loss of Supply	28,096,287	468,271	144,757	3.7%

Error			% of total:	0.2%
Cause	**Customer Minutes**	**Customer Hours**	**Customers Affected**	**Percent of Total**
Error- GPUE employee	855,348	14,256	18,684	0.1%
Error- Contractor	482,202	8,037	7,234	0.1%
Call-Error	281,872	4,698	1,965	0.0%
ERROR-COMP	52,843	881	548	0.0%
ERROR-CONTR	9,734	162	171	0.0%
Total:	1,681,999	28,033	28,602	0.2%

Weather			% of total:	0.1%
Cause	**Customer Minutes**	**Customer Hours**	**Customers Affected**	**Percent of Total**
LIGHTNING	764,949	12,749	2,617	0.1%
Flooding	55,972	933	78	0.0%
Salt Contamination	2,167	36	11	0.0%
Total:	823,088	13,718	2,706	0.1%

Outage Total:	**760,248,975**	**12,670,816**	**4,633,833**	**100.0%**

A final look at the individual outages results in Table 32. The causes listed in the outage information were grouped in eight rough categories. The first of these was “Other/Unknown,” the second was “Preventable,” the third was “Trees,” fourth “Non-Preventable,” fifth “Operations Related,” sixth “Loss of Supply,” seventh “Error,” and eighth “Weather.” In reviewing these eight groups, the four major groups are “Other/Unknown,” 34.5% of total consumer hours outage time, “Preventable,” 32.6% of total consumer hours outage time, “Trees,” 15.9% of total consumer hours outage time, and “Non-Preventable,” 9.7% of total consumer hours outage time. Again, the high number of consumer outage hours due to unknown causes in 2000 skewed the group labeled “other/unknown.” The notable result of this grouping is that the preventable group was presented as 32.6% of total outages. The major causes of outages in this group were electrical failure, corrosion/deterioration, mechanical failure and deterioration. Also, “Trees – Non Preventable” represents 12.2% of the total Customer Outage Hours. A regular right-of-way clearing program along with removal of rotten, leaning, and other danger trees outside the right-of-way will significantly reduce outages due to trees.

Although the CAIDI and SAIDI are high, there does not seem to be a decreasing trend in these indexes even with the elimination of major storm events. The fact that major events were removed from the indexes beginning in 1998 should have resulted in a noticeable decrease in the overall indexes for the last four years. Also, using the ten-year history as a benchmark only compares JCP&L's current reliability indexes to its historical reliability. JCP&L's reliability indexes goal should be at least the second quartile of surveyed utilities.

IEEE has spent several years working on a revision of standard 1366 "Guide for Electric Power Distribution Reliability Indices" that will define major events as relates to calculating and reporting reliability indices. This standard is in the final stages of review and should be available in the near future. The draft standard recommends reporting indices both with and without major events.

We recommend that JCP&L adopt the new IEEE Standard 1366 when final, particularly as relates to the definition and reporting of major event days. Indices should be calculated and reported both with and without major event days included. Although the indices including major events will be erratic, there should be a downward trend over time. Although events such as hurricanes and ice storms are unavoidable, a well maintained and operated system will experience less outages and shorter outages then one that is in poor condition.

We would recommend that the JCP&L CAIDI and SAIDI indexes be compared to the average of the 1990 and 1995 IEEE Survey second quartile results. This equates to an acceptable CAIDI of 1.3 and SAIDI of 1.5. The ten-year average for SAIFI of 0.97 is in the first quartile of the survey. We recommend that the JCP&L SAIFI be compared to the first quartile survey average of 1.0.

As indicated in the Executive Summary, Booth & Associates, together with Board Staff and the Company engaged in an iterative process which made significant progress towards addressing all recommendations and, insofar as the issues discussed above are concerned, to the extent that JCP&L agrees to fully comply with its Asset Management Strategy (AMS) document including the CRI program, which agreement is reflected in the Stipulation of Settlement (which includes the published AMS to which JCP&L has agreed to abide) entered into on June 8, 2004 by JCP&L and Board Staff (and which was reviewed and adopted by the Board), which resolves these concerns and recommendation.

Review of Subtransmission Planning Studies

JCP&L's Summer Operating Studies are a review of the subtransmission system which consists primarily of 34.5 kV in a network arrangement. This review includes both supply substations such as 230 to 34.5 kV, sub-transmission lines, various switching equipment, and of course, the loads at each distribution substation. The projections are done both at a 50/50 rating and a 90/10 rating. The 50/50 rating is based on a 50% probability that the actual peak load will exceed projected load or a 50% probability that the actual load will be less than the projected load. This would appear to equate to a projection of average loading. The 90/10 projections are based on the probability that there is a 10% chance that the actual peak will exceed the projected peak. This is equivalent to the projection of near extreme loads. Since summer peaks are most influenced by weather conditions, the 50/50 projections can be thought of as projected peak loads during normal summer weather conditions. The 90/10 would be those types of peaks that would occur during extreme weather conditions. Up through the year 2001, the 90/10 projections were used for "system normal" analysis. The 50/50 forecast was used for single contingency line outage analysis. Beginning in 2002, the 90/10 forecast was included for informational purposes only and was not used in the operating study. Also, the ratings, both normal and emergency, for distribution conductors, transformers, transmission conductors and transformers were based on a 35º C ambient temperature. Beginning in the year 2001, the subtransmission conductor's emergency rating was based on a reduced ambient temperature of 30º C. The normal ratings were still based at 35º C ambient and the emergency rating for distribution conductors and distribution transformers was still based at 35º C ambient. JCP&L cannot control the ambient temperature. Moreover, at peak loads the ambient temperature is typically at its highest for the season. This planning criteria change does not conform to good utility practice.

The typical improvements for the 5-year period appear to be adding anywhere from 130 MVAR to 300 or 400 MVAR of capacitors to the system each year. Part of these were added on the 34.5 kV and part of them to the distribution lines. There were also additions or change outs of 230 to 34.5 kV transformers most years. Anywhere from a half dozen or more sections of line in varying lengths were reconductored each year and there appeared to be a number of changes in open points and other switching operations to reduce loading on various lines or other components. In each year first contingency load flow analyses were performed for each of the 21 sub transmission areas. In each area, an analysis of each system of the area during first contingency outage resulted in recommended improvements along with switching procedures for the area.

Of notable importance is the fact that for each of the years from 1999-2002 there is a table that listed those substations for which auto-load transfer schemes should be disabled in order to avoid overloading of system components during first contingency conditions. In each of these years, the total number of substations for which auto-load transfer schemes were disabled exceeded 80 distribution substations. This means JCP&L installed equipment and expended substantial capital that cannot be used at the very times that they would most want to use it. Therefore, the rate payers are paying for something they are not getting because of the JCP&L planning methodology changes. In 2003 this list was not included; however, the format of the Summer Operating Study changed radically in 2003.

Since there would have had to been significant changes throughout the system or significant improvement throughout the system to avoid the need for disabling the automatic load transfer scheme, we would assume that this procedure is still taking place and it is just not clear from the new format.

Summary

Without sitting down with the engineers and reviewing each improvement in detail, a complete analysis or review of these operating studies can not be performed. However, the following conclusions can be reached based on the data in the reports and Booth review.

In 2001 and 2002, by lowering the ambient temperature during emergency conditions, the ampacity of the subtransmission conductors was artificially increased. In 2001, 48 34.5 kV lines were re-rated with higher ratings. In 2003, 30 lines were re-rated with higher ratings. In both cases these conductors were not replaced. This is not prudent utility practice and has the effect of lowering reliability by eliminating reserves to handle the periodic weather temperature and associated load extremes.

By disabling auto-load transfer schemes during the June – August peak load period for over 80 distribution substations, the length of time to which customers would be subjected to an outage for an open breaker or other component in the subtransmission system would be increased from almost instantaneous to the length of time required to perform a switching operation either manually or remotely, or more likely, to perform repairs since the system has been overloaded at this point in the operation.

Up to the year 2001, the 90/10 load forecast was used for system normal analysis. Beginning in the year 2002 the 50/50 load forecast was used for system normal analysis. This would effectively decrease the ability of the system to handle unusually high load due to weather during the normal configuration. Another way to look at this is that the point at which new system improvements are required would be delayed as compared to the system planning and design method used in the past when system normal analysis was based on a 90/10 load forecast. JCP&L is overstressing the system now and has a systematic plan to remove all reserve capacity and contingent capability. This is not prudent or customary utility practice. This will result in more outages and more extended outages.

The Summer Operating Studies only look one year into the future. There is no way of knowing whether or not proposed improvements will be overloaded or obsolete in 3 years, 5 years, or 8 years. There is no way to compare alternate improvements on a long-term cost basis. By reducing ambient temperature, deactivating auto load transfer, and changing the basis for design from a 90/10 to a 50/50 projection, JCP&L has increased the stress on the system and decreased its future options. JCP&L needs to adopt more reasonable criteria for circuit loading and future planning. JCP&L also needs to prepare a 10-year plan for the local transmission system. In particular, it should consider a plan for transferring portions of the distribution substation load from the 34.5 kV system to higher voltage transmission lines such as 115 kV. The intent would not be to replace the 34.5 kV system with a higher voltage system, but rather to gain capacity on the 34.5 kV system by selectively reducing load on the system, rather than attempting to pump more and more load through an already overloaded system.

In conclusion, we recommend the following:

- Return to using a 90/10 load forecast for system normal analysis
- Return to using 35º C ambient temperature and 2 feet per second wind when rating conductors and other components. Also, JCP&L should return to an industry standard of 75º C (167º F) conductor temperature for normal maximum ratings for local subtransmission conductors. For those newer lines designed to operate at 100º C, the 100º C (212º F) rating would be acceptable for temporary emergency operations.
- JCP&L should reconductor, add circuits and perform other improvements required to allow auto-load transfer schemes to function for first contingency subtransmission outages without overloading system components.
- JCP&L should prepare a 10-year local subtransmission plan. Furthermore, this plan should include an interim 5-year step. A new 10-year local subtransmission plan should be prepared every 5 years. This way, there is always 5 years of future planning in existence. This plan should contain both a clear set of design criteria and reliability criteria. It should also reflect the regions' Facilities Connection Requirements and other FCRs as filed at FERC. It should also consider a plan for transferring portions of the distribution substation load from the 34.5 kV system to higher voltage transmission lines for improved capacity and reliability.

As indicated in the Executive Summary, Booth & Associates, together with Board Staff and the Company engaged in an iterative process which made significant progress towards addressing all recommendations and, insofar as the issues discussed above are concerned, to the extent that JCP&L agrees to fully comply with its Asset Management Strategy (AMS) document including the CRI program, which agreement is reflected in the Stipulation of Settlement (which includes the published AMS to which JCP&L has agreed to abide) entered into on June 8, 2004 by JCP&L and Board Staff (and which was reviewed and adopted by the Board), which resolves this concern and recommendation.

Review of Protective Coordination Standards, Philosophies, and Methodologies

The IEEE Standard 37.91-2000 is the IEEE Guide for Protective Relay Applications to Power Transformers. Section 6 of this Guide states that, "fuses are commonly used to provide fault detection for transformers with minimum nameplate ratings up to 5,000 kVA. Transformers of 10,000 kVA and larger, three-phase, minimum nameplate are generally protected by a combination of devices. These devices typically are a differential relay, primary time-delay overcurrent relay, and instantaneous overcurrent relays, and a ground time-delay overcurrent relay on the secondary. A circuit switcher or relayed circuit breaker is shown on the high side, and an optional main secondary side protective device is shown on the secondary. This optional main secondary device would, of course, be a bus breaker. Feeder reclosers or breakers are not shown since these are not actually part of the primary transformer protection. To complete this statement, the common protection of transformers "transformers that fall between these two ratings (5,000 kVA minimum nameplate and 10,000 kVA minimum nameplate) are protected by either fuses or relays." Guidelines and procedures for performing both distribution and transmission studies are available from the Rural Utility Services (www.usda.gov/rus/), EPRI (www.epri.com) and other numerous books and utility standard practices and publications such as IEEE, ANSI, NESC, etc. Guides such as the IEEE C84.1 "Electrical Power Systems and Equipment – Voltage Ratings" and various manufactures tables such as conductor capacity tables will assist in the preparation of such studies. Among those publications available from Rural Utility Services are 1724D-101a "Electric system long-range planning guide," 1724E-202 "an overview of transmission system studies" and 1724D-101B "System Planning Guide - Construction Work Plans".

Jersey Central Power and Light has historically relied on large power fuses for transformer protection of the 34.5 distribution voltage transformers. As part of the Substation Protection Review for both regions, which took place during the last year, a number of substations were recommended for installation of transrupters and associated relays for high side protection. Whether or not these were done is uncertain. If not, they should be done immediately and additional substations should be reviewed for installation of transrupters and relays. Fuses do not provide adequate protection for transformers for major thru-faults, particularly since these fuses have to be over-sized, compromising protection in order to allow for the use of the normal rating for transformers which would be its maximum nameplate rating. The use of large power fuses also adversely affects coordination on the subtransmission system since any overcurrent relays would have to be coordinated with these relatively slow fuses. Differential relays are the preferred method for fault protection of the transformer itself and are many times faster than fuses and many times faster than overcurrent relays. JCP&L should complete a comprehensive substation protective coordination study.

The next item of concern is the settings for feeder breakers. Feeder breaker settings are substantially influenced by the high ratings for feeder conductors.

Feeder conductors are rated at 650 amperes or more. Accordingly, phase overcurrent relays would have to be set well above this level to allow for normal surges due to switching or capacitor operation. The use of such high levels of phase trip settings does not provide for adequate or customary protection for high impedance (low level) faults. The present JCP&L power line protection scheme constitutes an extreme hazard to the public and violates the principles of the National Electrical Safety Code. It also subjects line to a higher risk of burn down.

Another concern is that Jersey Central Power and Light does not use ground trip relays or ground trip settings on its breakers or three-phase reclosers. In fact, most line reclosers are either single-phase or three-phase with single-phase tripping. It is generally considered throughout the industry that ground trip relays and reclosers are required to meet the principals of the NESC and to use the vertical and horizontal clearance tables published in the NESC. Tables 232-1 and 234-1 of the National Electric Safety Code state that "Voltages are phase to ground for effectively grounded circuits where all ground faults are cleared by promptly de-energizing the faulted section, both initially and following the subsequent breaker operations." These tables set the minimum clearance between conductors and other live parts. Since they are the clearances that JCP&L uses in their line design, it follows that JCP&L must provide for prompt clearing of ground faults which requires the use of ground trip relays.

There are inherent enhancements to the three-phase tripping that will result from using ground trips. By using ground trip, the high impedance, low level faults are reduced in number and duration and the fault does not have time or energy to escalate to a major three-phase fault or to cause excessive damage to equipment or present a public hazard, which ultimately results in extended outages.

There are inherent problems in using high ampacity ratings for phase conductors. If a breaker or recloser trips on a line with high levels of load current, the number of consumers affected is excessive. Reducing circuit loading would greatly reduce the number of customers affected by an outage, as well as provide additional capacity for switching and load shifting during emergency conditions. Also, heavily loaded circuits result in greater unbalanced circuits which result in excessive levels of stray voltage. The planning criteria states that the distribution substation transformers can be loaded to 125 percent of maximum nameplate rating for summer normal peak and the Manager-Regional Engineering for each of the two regions confirmed this policy. The planning criteria also states that subtransmission substation transformers can be loaded to 118 percent of maximum nameplate rating. This policy is totally unacceptable and should be changed immediately. No transformer manufacturer would support such a policy and prudent utility practice does not support such a policy. The current practice will lead to substantially early failure of the power transformer. The same applies to excessive loading on transformers. Reducing the normal loading on transformers would allow added capacity for picking up load during transformer failures and other emergencies.

In reviewing Contingency Studies, it was noted that JCP&L performs almost no Distribution Contingency Studies. The Subtransmission Contingency Studies allow for open-ended local subtransmission line contingency during high load levels. Current loading of the distribution transformers and substation transformers and local subtransmission line result in the auto-load transfer scheme for over 80 substations having to be disabled each summer. Our recommendations are:

- A more reasonable level for circuit normal loadings should be adopted.
- Breaker phase relay settings should be reduced to match appropriate conductor loading.
- Contingency Studies for all distribution lines and substations should be performed.
- The number of circuits for the system should be increased by at least 50%, if not doubled.
- Ground trip relays must be installed on all transformers and circuit breakers.
- Three-phase reclosers should be retrofitted with ground trip relaying or sensing.
- A program of replacing large, single-phase reclosers with three-phase reclosers should be initiated. Single phase reclosers should be limited to 140 ampere maximum phase trip at which point three phase reclosers with ground trip should be applied.

In addition, the number of reclosers for the distribution system is inadequate for a system this size. One of the explanations for this practice could be linked to the high levels of circuit loading. It is very difficult to size and coordinate reclosers when conductors are loaded above prudent levels. In fact, there are probably many places on the circuits where reclosers, particularly single-phase, could not even be used. By adding circuits, reducing breaker and recloser settings, adding reclosers, reducing loading on transformers and reducing loading on the 34.5 kV transmission system, the reliability of this system should increase substantially.

Current JCP&L design standards only require a loop type feed for underground subdivisions of 40 or more customers. This should be changed to 5 or more customers. Service restoration of underground circuits is typically significantly longer than that of overhead circuits. The installation cost of a loop feed to underground subdivisions is not significantly greater than a radial feed. Also, this expense is typically paid by the developer and not JCP&L.

Distribution planning studies should be prepared each year. These studies should be based on three or more years of projected growth. The projections should be the 90/10 projections rather the 50/50 projections. Improvements dictated by the plan should be implemented prior to the summer peak each year rather than in response to the previous summer peak.

In conjunction with the recommended distribution planning studies, a distribution contingency study should be prepared for the entire distribution system.

Although it may not be feasible to provide contingency backup service to all feeders, it should be the goal of JCP&L to provide backup from same sub feeders or from other sub feeders for most circuits. Along with feeder contingency, distribution substation transformers should be loaded such that other transformers in the same substation or in adjacent substations can serve the load if any single transformer fails.

Paragraph 4 of the MOU in which JCP&L is committed to continue and complete its accelerated reliability program as described therein, which, among other things, includes the fusing of certain circuit lateral taps, where necessary and possible, as well as certain main feeder sectionalizing, consistent with JCP&L's circuit protection philosophy, resolves these concerns.

In addition, as indicated in the Executive Summary, Booth & Associates, together with Board Staff and the Company engaged in an iterative process which made significant progress towards addressing all recommendations and, insofar as the issues discussed above are concerned, to the extent that JCP&L agrees to fully comply with its Asset Management Strategy (AMS) document including the CRI program, which agreement is reflected in the Stipulation of Settlement (which includes the published AMS to which JCP&L has agreed to abide) entered into on June 8, 2004 by JCP&L and Board Staff (and which was reviewed and adopted by the Board), which resolves this concern and recommendation.

Objective Performance Standards

Regulators in more than 30 states have identified reliability metrics they either require or expect to be reported by electric distribution companies. Of the 30 states that have identified specific reliability metrics, 20 use SAIFI, SAIDI, and CAIDI. Nine states include MAIFI in their reporting.[2]

There are many deficiencies associated with evaluating reliability indexes and comparing utilities using SAIFI, SAIDI, or CAIDI. Those deficiencies include:

1. Average reliability numbers do not provide the appropriate reflection of reliability in specific areas of the system;

2. Average system reliability numbers do not adequately reflect the reliability for a particular customer class such as critical industrial customers, life support customers or large commercial loads with critical operations;

[2] Bruce Humphrey, "Mixed Signals Cloud Reliability Picture," *Platts Energy Business & Technology,* September 2002, Vol. 4, No. 5, pp 49-52.

3. Average system reliability numbers do not adequately reflect the interruption scenario cost imposed on customers, particularly commercial and industrial customers;

4. Average system reliability indexes provide absolutely no assessment of overall power quality issues which are often as important to certain customer classes as average system availability.

In our opinion, SAIFI, SAIDI, and CAIDI are currently the best available metrics to measure and report overall system reliability performance. These metrics need to be used until new standard performance metrics are developed and adopted industry-wide.

The preferred consistency within the industry would be to adopt the major event standard/procedure in the revised IEEE Standard 1366 once published. The recommended indices should be reported both with and without major events.

We are in agreement that FirstEnergy's CRI measurement is a good addition to reliability measurement, but not as an overall system tool. Its value lies in how regulators treat individual circuits and service areas. In our opinion, circuit-by-circuit differences in reliability performance are entirely appropriate and are the only way to begin to correlate electric reliability and customer satisfaction. Furthermore, the FirstEnergy CRI level of 130 is not adequate for all feeders.

Recommended Performance Standards

We propose the following approach: a combination of System Overall and System Component Performance Standards:

System Overall Performance Standards:

1. Action will be taken if system reliability indexes excluding major events exceed the following level:

   CAIDI – 1.3 hours
   SAIDI – 1.5 hours
   SAIFI – 1.0 interruptions

   Note: It is critical to redefine "major events" since the JCP&L definition is too liberal and does not appropriately reflect the magnitude of reliability deficiency.

2. The definition of *major event* shall include the following:

   Wind Storm – 50 mph sustained winds for one hour.
   70 mph gusts.

   Ice Storm – Accumulation equal to or greater than ½”.

   Snow Storm – Accumulation equal to or greater than 3”.

   Hurricane – Declared Disaster.

3. Generation and transmission (≥ 115 kV) outages shall be excluded from the calculation of the metrics.

4. JCP&L should achieve the goals in Item 1 within five years. The acceptable levels for each of the first five years will be the 2003 index minus the year number (1, 2, 3, etc.) times the difference between the 2003 index and the target index listed in Item 1.

System Component Performance Standards:

A. Substation Capacity

1. When actual load reaches 95% of nameplate transformer capacity, JCP&L shall develop and budget a remediation plan composed of one of the following actions:

   (a) Replace transformer
   (b) Add transformer capacity in substation
   (c) Shift load so that the transformer is less than 80% loaded based on nameplate rating
   (d) Shift load to a new transformer.

2. When actual load reaches 110% of the nameplate rating, implement the remediation plan within 90 days.

B. Feeder Circuits

All of JCP&L’s circuits will be classified into one of the following types of feeders that must meet the following criteria:

1. Industrial

   (a) Defined as any circuit that serves at least one customer with a peak load of ≥ 1,000 kW or uses more than 5,250,000 kWh per year.

(b) Action is required when the circuit CRI exceeds 80 or momentary outage for any industrial customer exceeds five per year.

2. Commercial

(a) Defined as any circuit that serves ten or more customers using over 680,000 kWh per year.
(b) Action is required when the circuit CRI exceeds 100 or momentary outages exceed 20 per year per feeder or the SAIDI is ≥ 1.5 hours per feeder.

3. Urban – Residential

(a) Defined as a circuit operating at 300 amps or more normal peak or customer average use greater than 1,200 kWh per month.

(b) Action is required when the circuit CRI exceeds 100 or momentary outages exceed 30 per year per feeder or SAIDI ≥ 3.0 hours per feeder.

4. Rural – Residential

(a) Defined as a circuit operating at less than 300 amps per phase per feeder annual peak or average customer use less than 1,200 kWh per month.

(b) Action is required when the circuit CRI exceeds 130 or momentary outages exceed 40 per year per feeder or SAIDI is ≥ 5.0 hours per customer or feeder per year.

Circuit Feeder Action Plan

JCP&L must implement its current "Worst Performing Feeder Program" approach to develop a remediation plan for all circuits not meeting the system component performance standards; i.e., review the cause, trouble location, and duration of each interruption, review circuit map to determine how circuit configuration and trouble location contribute to the magnitude of the outage and a visual field inspection of the circuit. Analyze the circuit loading to determine its impact on the following:

1. Contribution to outage (unnecessary relay operations, component overloading, etc.)

2. Ability to restore service without sectionalizing circuit (co-load pickup).

The employee performing the feeder inspection shall have a good engineering and construction background to remediate all the problems. JCP&L's remediation plan must include upgrading the line to current construction standards and NESC requirements including but not limited to pole replacement and structure strength requirements.

C. UG Faults

1. Any section of underground cable experiencing more than two faults in two years excluding dig-ins or other external damage shall be replaced.

2. Any underground cable with exposed concentric neutral exceeding 15 years age shall be tested every three years to assess the condition of the concentric neutral. If the original installed standards are not met, the cable sections shall be replaced.

D. OH Conductor Standards

Overhead conductors shall not be operated in excess of the following standards:

1. Distribution voltages – current loading using 167° F normal design, 2 fps wind velocity, 35° C ambient and sun. For load transfer, 200° F emergency. The following table shows sample conductor rating at these criteria.

Table 33
Recommended Distribution Conductor Ratings

Conductor	Normal Rating Amps	Emergency Rating Amps
336.4 ACSR	417	573
556.5 ACSR	565	786
795 ACSR	707	995
397.5 AAC	450	618
556.5 AAC	553	766

2. 34.5 kV local transmission – all network operating conditions must contain single contingency planning. Current loading at 212° F normal design, 2fps wind velocity, 35° C ambient and sun. The following table shows sample conductor rating at these criteria:

Table 34
Recommended Local Transmission Conductor Ratings

Conductor	Normal Rating Amps	Emergency Rating Amps
336.4 ACSR	417	609
556.5 ACSR	565	836
795 ACSR	707	1061

E. Min/Max Voltage

The minimum and maximum service voltages shall meet the Electrical Power Systems and Equipment Voltage Rating (60 Hz) specified in ANSI C84.1-1995.

F. Power Factor

JCP&L shall maintain lagging power factor at 99% in June-September and December-March, and 96.5% at other times at all distribution substations measured at the high side terminals of each transformer. Leading Power Factor during non-peak periods should not exceed 98%.

G. Power Quality

JCP&L shall meet all requirements for IEEE-recommended practices and requirements for harmonic control in electrical power systems, IEEE Standard 519-1992 Section 10 – Recommendations for Individual Customers and Section 11 – Recommendations Practices for Utilities.

H. Facilities Connections Requirements (FCR)

JCP&L shall meet or exceed the FCR published by PJM.

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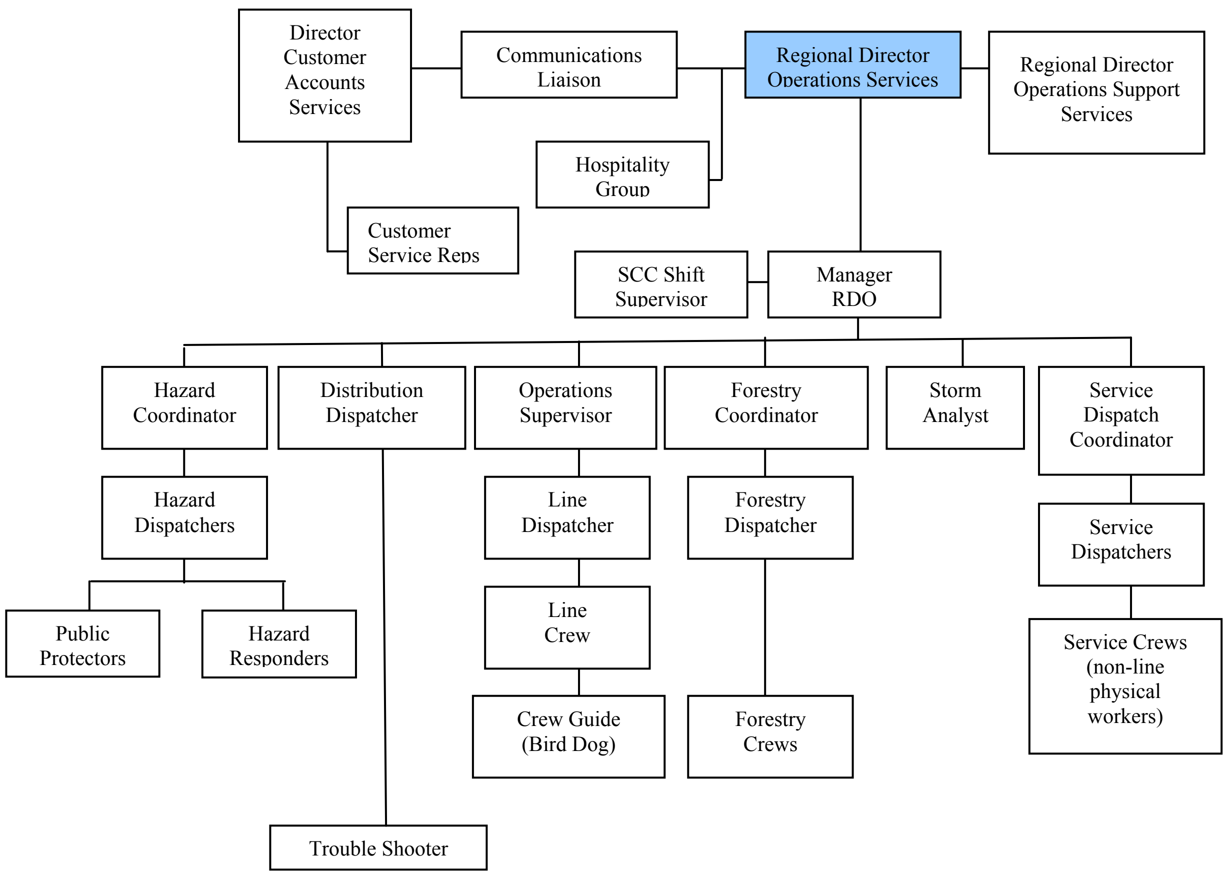
9. Outage Management

Emergency Storm Restoration Plan (ESRP)

JCP&L operates under a corporate-wide Emergency Storm Restoration Plan ("ESRP"). A Storm Management Team composed of the following members shown in Figure 18 implements the ESRP:

Figure 18
Storm Management Team



When severe weather is imminent, the Regional Dispatcher initiates the ESRP process by notifying the Storm Management Team. The Regional Director Operations Services is responsible for implementing and directing storm restoration during emergencies. This responsibility is rotated to the Director Operations Support Services when the Regional Director Operations Services is not on duty.

JCP&L's approach is a "cut and run" approach. Hazard responders are dispatched to identify dangerous sites and situations. These are isolated and repaired at a later time by line crews. The work process for a storm is no different than daily work, the difference being a greater number of crews are dispatched throughout the system performing the work.

FE's goal is to have a Damage Assessment team prepare a detailed assessment of a storm within six hours. If the overall assessment indicates that service to all customers cannot be restored within 24 hours, internal or external assistance is requested. The Storm Management Team uses *PowerOn* as its primary tool to manage events.

PowerOn

PowerOn is a General Electric proprietary product intended to provide enhanced automation for outage management purposes. As with many automated outage systems available in the electric utility industry, it is relatively new and affords great opportunities. However, the systems are constantly being enhanced and improved with their inherent initial deficiencies having to be identified and rectified throughout a multi-year implementation process. Furthermore, PowerOn, as with many other electric utility software, is not fully integratable with other software. Therefore, there is and can be duplication of effort. PowerOn is an excellent outage management tool; however, as implemented by Jersey Central and First Energy, and as continuing to be modified and enhanced with a new version currently in the implementation process, there are some deficiencies. The most notable PowerOn deficiency is the fact that the AM/FM system does not directly integrate to SmallWorld and SmallWorld GIS that serve as the platforms for the outage management software of PowerOn. Interviews with the Jersey Central personnel indicate that they are in the mode of manually updating SmallWorld GIS from the AM/FM database. This introduces two distinct problems. First, there is already a delay of the AM/FM system information being disseminated based on actual field changes, additions and modifications. Once this information is available, the information then has to be re-input to the GIS system manually in the SmallWorld GIS. This introduces additional delays which can be from as little as three weeks to potentially as much as three months and possibly even longer. Thus, enhancements, switching changes, additions or modifications in the system may not be recognized by dispatch and the EMS for energy management systems' purpose or outage management and prediction purposes until long after implementation. This can result in not only delays in outage restoration; it can and may also present some inherent dangers to the public and employees.

Discussion with the Jersey Central personnel indicated that their preference was to leave the system this way and require the manual insertion of the AM/FM data into the SmallWorld GIS. This is not believed to be the most prudent way in which to proceed and is inconsistent with the processes of most utilities for which we are familiar. Additionally, the data as input into the SmallWorld GIS is done in such a manner that any errors can and will compound the problems, and no quality control, quality assurance or other checking or verification system was identified. Therefore, once a mistake is entered, it can remain in the system indefinitely.

Considering that the Call Center and the dispatchers currently count very heavily on the interface and predictive modeling capabilities of PowerOn, it is unfortunate that Jersey Central has elected to have a compounded manual process and not a seamless, automated process from the AM/FM system through the PowerOn system. This is a deficiency that should be corrected over time. However, it should not be given an extremely high priority since the PowerOn system and the automation capabilities of that system substantially enhance response time, outage prediction and restoration capabilities through the automation process, from what Jersey Central and First Energy were capable of providing under a substantially manual system and not an automated system with PowerOn. There can be flaws in our examples of how such a deficiency can exacerbate frustration and extend outages through failure to recognize new load transfer capabilities. It is, however, a refinement and improvement that should be carefully considered for the future.

Paragraph 1 of the MOU, which provides that JCP&L will conduct a GIS field audit and provide status reports with respect thereto, resolves this conclusion and recommendation.

21st Century

21st Century is an automated telephone answering system. It was implemented and taken live in June 2003. In interviews with the manager of the Call Center, it was determined that 21st Century, after only a few months of implementation, was determined to have some significant deficiencies, the most notable of which is the customer's inability to exit the system and have access to a representative. The system as currently installed and implemented is a fully automated system with no ability for access to a live person. Jersey Central recognized this deficiency and is moving to implement a new enhanced system to allow for access to live representatives. The projected date for the new enhanced 21st Century system is the end of January 2004.

Call Center

The Call Center in Reading, Pennsylvania was evaluated. This evaluation included interviews, data analysis, quantitative surveys and anecdotal information.

On the day of the Call Center visit and interviews, the center was in the early stages of its move to a new facility. The Call Center is in the process of implementing new, more representative, friendly, and enhanced windows-based software in a new state of the art facility. Such a move and enhancement will have its challenges and may result in some short term decline in Call Center reliability; the Center should be at an equal or higher level of efficiency than currently exists. This report deals with the existing Call Center, its procedures and methods and interfaces to the other operations and software of Jersey Central and First Energy. From all indications, the Call Center personnel in Reading, Pennsylvania are skilled and trained at or above utility industry and Call Center standards. Reading, Pennsylvania has Penski Call Center located in that community and will also be getting a Verizon Call Center in that community. The manager of the center indicated that First Energy is committed to hiring and maintaining the "cream of the crop" by providing the best work environment, benefits and salary. Given the apparent utilization of Reading, Pennsylvania by several major corporations for Call Centers, this should provide a readily available, highly skilled and trained workforce in this community. This should serve to benefit Jersey Central, First Energy and its customers as long as management remains committed to hiring and maintaining the most skilled and dedicated employees for its Call Center.

The Call Center has available real-time querying process. The floor managers and the Call Center manager use this information to monitor on a real-time basis and to assess the operating efficiency of the representatives and to assure that the necessary resources including Call Center representatives are at an adequate level to meet the needs of the customers.

Among the most telling of all commitments in the Call Center were the policies, procedures and attitudes of management and employees towards the on-call call-in commitment. When employees are on call for the purpose of the necessary increased staffing during emergency conditions, including but not necessarily limited to predicted storms, the Call Center management has indicated that there is a 100 percent response rate and zero tolerance for failure to arrive within 30 minutes of being called. There is a clear indication that the Call Center has the highest of commitments to the response associated with emergencies and storms.

The Call Center uses SAP and PowerOn as part of its tools. It has a sophisticated AT&T communication system with redundancy in all levels of communication and power supply including backup generation. Additionally, recognizing the multiple levels of redundancy, the Call Center also has an emergency blackout procedure and randomly, without warning, implements a drill at least once every year to assure that the emergency backup system functions seamlessly and effectively. Although a complete loss of power and 100 percent of the communications has never occurred, Jersey Central and First Energy have a procedure in place which is periodically and randomly tested to assure live implementation if necessary. The Call Center understands it is the first line of communication, whether it is a 911 utility emergency situation such as a live line down or is simply a customer contact for the purpose of billing or new service. For the purpose of this report, the Call Center evaluation and analysis was limited to system reliability and outage restoration issues. The Call Center data and interface was directly to SAP. The Call Center relied heavily on PowerOn for queries on estimated time of restoration and other outage management information. The flow diagrams attached in Appendix F were discussed and evaluated. Additionally, data requests and information were evaluated and associated with the large array of real-time queries exclusive to the Call Center including the query database. The items queried on a real-time basis and which are maintained in a database for assessment of efficiency, needs and planning are shown in Appendix G.

The Call Center has in place and runs drills, and efficiently operates its management and staff to plan, prepare and function during emergencies and predicted storm events. The Center has analysts who do and can provide substantial support, whether they are in the Call Center or stranded from the Call Center as the result of a weather event. They have the standard array of continued communication tools, even when not at the Call Center, including internet access and connection to the Call Center, and the activities, pager and cell phone communications. The Call Center monitors the weather station and the local weather information. The Call Center does not however, have available or utilize the National Weather Station real-time radar. Although, this could be an enhancement and a tool for the Call Center management, it is quite apparent that the Call Center, its management and staff implement emergency activities well in advance as a result of the information they currently use and real-time National Weather Service radar information will only provide potential for optimizing personnel time utilization and potentially avoid the Call Center gearing up and implementing emergency procedures earlier. The Call Center's "war room" for emergencies and storm events is substantially manned by analyst and management at the Call Center. Our evaluation did not determine any deficiencies associated with the Call Center. Upon implementation of the new Call Center facility and equipment, there should be an additional investigation to assure that the Call Center capabilities, staffing, management and commitment are maintained or enhanced beyond the current level.

We did not identify any functional reason for the Call Center to be located in New Jersey. As any national organization whose Call Centers are located in an array of locations across the country, the First Energy Call Center providing service to Jersey Central appears to provide seamless Call Center activities to the Jersey Central customers.

Jersey Central is able to maintain a substantially more robust management and analyst capability at a larger facility servicing a more substantial service area. Additionally, the overall infrastructure and capabilities of a larger, more robust facility will provide enhanced capability to respond to emergency and storm related outage activity demands. De-centralizing the Call Center activity would be counter productive. This would reduce the robustness capabilities including management analyst and infrastructure. The reality of a Call Center is that there is a distinct functional activity to be performed by the Call Center and representatives answering the phones and responding to the needs of the customer. This functionality would not be enhanced by local presence or knowledge. Whereas a dispatch center within a specific region can and should be enhanced by local knowledge and involvement within the system infrastructure. This is to say that the regional RDO should clearly enhance their effectiveness in the system operations including outage management and energy management activities, particularly with the second tier support from the transmission dispatch facility. The same enhancements are not achieved by de-centralizing Call Centers. We could identify no deficiencies in the current Call Center procedures, activities, and functionality. The First Energy Call Center servicing, among its company's Jersey Central, appears to be in all areas at or above electric industry standards.

Crew Utilization During Emergencies

To assess crew utilization during emergencies, we have reviewed documentation from JCP&L's response to major events:

- August 2, 2002 storm – heat-related storm
- September 18-21, 2003 – Hurricane Isabel
- July 5-8, 2003 – Barrier Peninsula 34.5 kV outages

August 2, 2002 Storm

During the week of July 29, 2002, New Jersey experienced high temperatures and humidity which ultimately led to a severe summer storm event. JCP&L set a new all-time peak of 5,810 MW on Friday, August 2nd. The peak number of customers out of service was 176,458 customers; 1,029 trouble locations occurred in the JCP&L service regions. The Northern Region experienced a typical thunder and lightning storm starting at approximately 5:30 p.m. that resulted in 442 outages affecting approximately 8,700 customers. Approximately 80% of these customers were restored within 48 hours.

The storm that impacted the Central Region at about 8:30 p.m. resulted in approximately 180,000 customer outages. Severe thunderstorms with over 4,000 lightning strikes and high velocity "straight-line" wind gusts of 60-70 mph brought down tree limbs and entire trees. In the first 24 hours, JCP&L restored service to over 90,000 customers. However, complete restoration was not achieved until five days after the storm hit. Total duration of the event was approximately 126 hours.

Table 35 below shows the number and composition of crews working on storm restoration during this event:

Table 35
Hourly Profile – Number of all Crews Working on Storm Restoration
From Storm Inception until all Customers Restored
August 2, 2002 Storm

	Total FE Crews	Contractor Crews	Foreign Utility Crews	Total All Crews
8/3/02 2:00	29	0	0	29
8/3/02 6:30	45	0	0	45
8/3/02 14:30	72	4	0	76
8/3/02 19:30	74	4	0	78
8/3/02 23:00	33	4	0	37
8/4/02 5:00	44	6	4	54
8/4/02 9:00	82	6	4	92
8/4/02 15:00	93	6	4	103
8/4/02 19:00	57	10	6	73
8/5/02 1:00	36	0	6	42
8/5/02 4:30	28	6	6	40
8/5/02 9:00	73	20	15	108
8/5/02 12:00	134	20	15	169
8/5/02 17:00	121	20	15	156
8/5/02 21:00	113	14	5	132
8/6/02 1:00	60	4	4	68
8/6/02 6:30	66	6	4	76
8/6/02 10:00	158	20	21	199
8/6/02 15:05	150	20	27	197
8/6/02 20:00	146	20	23	189
8/7/02 1:00	96	14	33	143
8/7/02 4:00	121	14	50	185
8/7/02 6:00	193	0	33	226
8/7/02 10:00	221	0	49	270
8/7/02 14:00	206	0	45	251
8/7/02 18:00	165	0	22	187

Most crews were comprised of two or three men. Eighty-six crews were tree crews only.

September 18-21, 2003 – Hurricane Isabel

Effective management and planning began early during Hurricane Isabel, beginning on September 8, 2003. By Wednesday, September 17, 2003, JCP&L had assembled in New Jersey approximately 1,530 FirstEnergy workers. As the storm began to impact New Jersey on Thursday afternoon, September 18, 2003, the

JCP&L service territory received approximately 30 to 40 mile per hour sustained winds with gusts up to 60 miles per hour. During the storm, approximately 192,000 JCP&L customers lost power, with the largest number of customers without power at any one point in time being 74,270. Total trouble locations were 1,086 and 87.3% of the customers were restored 24 hours after reaching the peak of 74,270 outages. Of JCP&L customers, 95.6% were restored within the first 48 hours of the storm. Total duration of the event was approximately 75 hours. Table 36 below shows the number and composition of crews working on storm restoration during Hurricane Isabel:

Table 36
Hourly Profile – Number of all Crews Working on Storm Restoration from Storm Inception until all Customers Restored
September 19-21, 2003 – Hurricane Isabel

Date	Time	JCP&L	Ohio	Contractor	Total
18-Sep-03	3:30 PM	82	0	0	82
	7:30 PM	86	0	0	86
	11:30 PM	109	0	0	109
19-Sep-03	3:30 AM	172	0	0	172
	7:30 AM	207	60	19	286
	11:30 AM	193	60	19	272
	3:30 PM	208	60	19	287
	7:30 PM	206	60	34	300
	11:30 PM	192	37	48	277
20-Sep-03	3:30 AM	107	0	48	155
	7:30 AM	109	23	50	182
	11:30 AM	125	23	50	198
	3:30 PM	116	36	50	202
	7:30 PM	108	36	50	194
	11:30 PM	110	36	50	196
21-Sep-03	3:30 AM	47	36	50	133
	7:30 AM	53	0	48	101
	11:30 AM	79	0	50	129
	3:30 PM	83	0	50	133
	7:30 PM	73	0	50	123

Typically, the crews were two-man crews, but three-man crews were deployed when required. Trouble crews were typically one-man. Service crews were typically two-man crews. A total of 211 tree crews, all contractor, were available. No foreign utility crews were requested.

During the August 2002 Storm response, JCP&L utilized only 120 of their 560 trained Hazard Responders. During Hurricane Isabel, JCP&L reported that they had approximately 400 hazard responders on their property at the beginning of the storm.

The inability to get sufficient repair crews into the field until 58 hours into the outage was a primary cause of the ineffective response to the August 2002 event. During Hurricane Isabel, 286 total crews were in the field within 28 hours.

July 5-8, 2003 Barrier Peninsula Outage

The July 2003 Barrier Peninsula outage was not similar to the two events discussed above. The events which led to the power interruptions to customers on the Barrier Peninsula involved five primary locations on the 34.5 kV subtransmission system that supplies power to the area. Many of the customers who experienced loss of power receive their service from local municipal utilities who operate the 12.5 kV and lower distribution systems but are supplied from JCP&L's 34.5 kV lines and substations. Multiple faults in the 34.5 kV system resulted in insufficient power being delivered to all distribution substations. The majority of the customers experienced outages because of this lack of power supply, even though the distribution facilities were functioning properly. JCP&L's response to this event involved repair to underwater cable by specialized cable crews, repairs to overhead portions of the 34.5 kV system, and resolving distribution equipment problems such as blown fuses and distribution transformers that were caused by the original subtransmission failure.

The peak number of customers out of service was 34,080, and 5 subtransmission trouble locations and 14 distribution trouble locations were involved. Callout response was not a problem. No foreign crews were requested. Table 23 shows the profile of the crews working on restoration during this event:

Table 37
Hourly Profile – Number of Crews Working on Storm Restoration from Storm Inception until all Customers Restored
July 5-8, 2003 Barrier Peninsula Outages

Date	Time	Total Crews
7/5/2003	12:00	15
	16:00	16
	20:00	19
7/6/2003	0:00	25
	4:00	29
	8:00	26
	12:00	26
	16:00	29
	20:00	42
7/7/2003	0:00	39
	4:00	29
	8:00	58
	12:00	47
	16:00	38
	20:00	23
7/8/2003	0:00	16

There was a maximum of 58 line crews working in various areas at different times. These were specialized crews including JCP&L's Transmission Construction and Maintenance Team (TC&M) and cable crews.

10. Compliance with FE/GPU Merger Stipulations (EM001108701)

This section contains the results of our review and analysis of applicable FE/GPU Merger Stipulations and reports JCP&L's compliance or non-compliance, as well as, the actions taken under the stipulations and their impact on the reliable operation of JCP&L.

Stipulation 25 –

> *"First Energy has provided, subject to a claim of confidentiality, to Board Staff and the Ratepayer Advocate a detailed (although preliminary) plan delineating the post-merger organization of the Northern and Central Regions by job title and function. Although the final organization will not be determined until or about the time of consummation of the Merger, FirstEnergy commits that the staffing of such JCP&L regional organizations in terms of numbers of positions, responsibility, authority and functions will be almost totally unaffected by the Merger. More particularly, FirstEnergy has represented that as a result of the merger and over the next several years, it is anticipated that approximately 1,250 employee positions will be eliminated or consolidated as a result of the merger. Of that total, depending on severance package acceptance, as well as the location of personnel with virtual offices and other factors, it is anticipated that between 185 and 225 of those positions will be within JCP&L's or GPU's operations in New Jersey over the twelve months following consummation of the merger, and that between 250 and 300 of the positions ultimately eliminated will be within JCP&L's or GPU's New Jersey operations. FirstEnergy also has provided, subject to a claim of confidentiality, to Board Staff and the Ratepayer Advocate, the preliminary plan outlining the proposed structure of JCP&L's current rates, legislative, regulatory and customer choice functions and the Executive Office of Consumer Advocacy. FirstEnergy shall maintain an adequate number of positions staffed with people familiar with New Jersey's and JCP&L's rates, regulatory, reliability, engineering and labor relations matters. Within 60 days of merger closing, FirstEnergy shall provide final organization charts for JCP&L's Northern and Central Regions to Board Staff and the Ratepayer Advocate."*

Based on our interviews and inspection of data provided by JCP&L in response to our Data Requests, we believe JCP&L is in compliance with Stipulation 25.

Throughout this audit, we interviewed JCP&L staff members representing the bargaining unit, management, and elected or appointed officials, and other area citizens who provided various opinions concerning staffing issues. JCP&L management felt that staffing was adequate and complied with the merger and employment agreements. Although, JCP&L did not force anyone to retire or resign, some employees did so voluntarily but may not have been replaced. Thus, JCP&L submits they have met their employment agreements. JCP&L's bargaining unit is concerned about a staffing shortage. According to the Bargaining Unit, the staffing level today compared to years ago has decreased because management has not replaced those employees who have retired or resigned. In the merger agreements, management had the discretion to fill these positions as they deemed appropriate. Some of the elected and appointed local government officials stated there were not enough personnel working with JCP&L.

The following three paragraphs are a reflection of interviews and subjective in nature. We believe this report should include this subjective discussion particularly since reliability is often subjective from the customer's perspective.

Outages and duration seem to be focused around the number of available employees. The assumption is that if JCP&L had more people on staff, the outage period would be shorter, the frequency would be less and staffing would be adequate to get the work completed. Some of the previous reports from other consulting groups have compared miles of line, number of customers per lineman, and other benchmarks that utilities use when comparing number of personnel. However, every utility varies in density, miles of line, commercial and residential mix, and business as it relates to the residential and commercial mix. These factors contribute to the number of people necessary for the utility to provide adequate service. If JCP&L were not having reliability problems and power outages, the number of personnel working for the company probably would not be an issue to the NJ Board of Public Utilities or the public.

If it takes more employees to improve service reliability, then that is a decision JCP&L must make. Rather than micro-managing the utility and giving them a finite number of employees they need to add whether it be engineers, lineman or underground technicians, the real issue should be that JCP&L should be held accountable for reliability. If reliability is not adequate, JCP&L is responsible. JCP&L should decide whether they need personnel, contract services, or spend more money on capital and maintenance. If JCP&L cannot solve the reliability issues, the appropriate action should be taken by the NJ Board of Public Utilities.

Service was identified as a major problem by many of the elected and appointed officials interviewed. They cited a decline in service beginning with GPU and continued to worsen with the most recent merger. It took weeks to get a street light repaired and 24 hours or so to get a line out of the way that would have taken no more than 15 minutes had the JCP&L staff arrived on the scene to correct the problem and then been able to open up a main thoroughfare. Appointed officials are quoted to say "if something is not done soon there could be a citizen uprising." They feel the situation is critical.

Based on our interviews with some of the JCP&L staff members, many of the employees make a great deal of overtime. One interviewee cited that he had made over a thousand hours of overtime thus far this year and that he was not one of the high earners of overtime. One thousand hours of overtime spanning one year is an average of 20 hours a week beyond the 40 hours of regular time. Also, according to JCP&L staff, the reason for the overtime was strictly for power restoration during outages. Overtime is not authorized for regular operations and maintenance.

The field audits of the equipment and facilities indicate inadequate spending to maintain the utility system at the proper level has been the past practice. Therefore, rather than addressing service issues, including new service, street light installation, repairs and routine maintenance, JCP&L employees are spending most of their time restoring power. This would not be a problem if the money and resources were allocated to resolve the problems identified in our inspections and observations. Staffing is a minor issue compared to the reliability factors that require proper planning and allocation of resources. Staffing requirements can then be determined once these decisions are made.

Stipulation 26 –

> "*JCP&L shall honor all JCP&L pre-merger contracts, agreements, collective bargaining agreements and commitments that apply to current or former employees of JCP&L as well as all present obligations to employees from pre-existing pensions and retirement benefits, whether presently vested or contingent, as they become due."*

Stipulation 27 –

> *"FirstEnergy shall honor the Memorandum of Agreement ("MOA") contract extension with JCP&L's bargaining unit employees (approximately 1,600 employees) that through October 2004 protects against involuntary layoffs and provides for increases in compensation and benefits. FirstEnergy, to the extent deemed necessary by regional management, shall backfill, through employees and/or contractors, JCP&L's regional service reliability employees who may either retire or voluntarily resign through October 2004, so that the appropriate staffing level is maintained to assure safe, adequate and proper service. Regional management shall maintain staff at district offices sufficient to maintain reliability and service in compliance with Board requirements and orders."*

We believe stipulations 26 and 27 are related and therefore address them as a combined issue. JCP&L management stated they have complied with all the agreements and stipulations set forth by the merger. Management recognizes that collective bargaining problems exist and they are working towards a resolution. The collective bargaining group has a different view. They believe that JCP&L may be complying with the agreements because they have a different interpretation of what some of the words mean in the agreement. With that, they hold that JCP&L allows grievances to carry on rather than mediating and attempting to reach a settlement. It was not clear how accurate these statements are, however, they are consistent with previous reports citing the disconnect between management and collective bargaining, and the need to get the issues resolved.

Stipulation 30 –

> *"FirstEnergy shall use its best efforts to implement its Power Systems Institute training program for linemen and other skilled electrical workers in JCP&L's territory, tailored to meet the specific needs of JCP&L's service territory."*

A concern voiced by the BPU was the proper training of linemen working on JCP&L's system. As people retired, would JCP&L have employees qualified and trained to move up into the position vacancies. The new program that JCP&L has put in place, called PSI, is a hybrid of a lineman training program and an Associate Degree program. The collective bargaining employees felt like general training was nonexistent or "a joke" as it was expressed in the interview discussions. They expressed concerns about people having to quit their job in order to go through the training program with no guarantee of getting a job after they completed the degree program. Booth & Associates, Inc. visited the Phillipsburg, New Jersey Training Center to investigate the PSI program.

The Phillipsburg location is where the potential candidates for employment get their hands-on and classroom training specific to electric distribution overhead line, substation and underground distribution work. We found the facilities provided by JCP&L to be very good. The equipment necessary for training was also noted to be very good. The modules for the different components of training were more than adequate as well as the instruction (See Appendix H). We were impressed with the facility. Anyone that successfully completes the program should possess adequate knowledge of electric distribution work and how to handle issues in the field. Experience would be beneficial to enhance the training. The facility, the training equipment, and the instructors were very impressive. Only three candidates are currently enrolled in the new program which created some concern.

We questioned where the incumbent employees are who were enrolled in the training prior to the merger. We learned of another facility in Phillipsburg, Pennsylvania where eleven JCP&L employees are currently enrolled in the training program. Their enrollment offers paid class time which is how the original program was set up prior to the merger.

Recruiting employees from within JCP&L for advancement to lineman or technician, like meter readers, may be a problem in the future. They would be required to quit their job to participate in the training program. As impressive as the program and the people managing it are, it is not serving JCP&L well. We would never discount the value of having a lineman or any employee getting an Associate Degree. We certainly promote as much formal education as anyone can get. However, there may be a place in this training for both. Having an Associate Degree certainly brings value to an individual; it also increases their personal and professional satisfaction and accomplishment. But there could be some scenarios where having an Associate Degree is not as important to an employee as going through the training program without the college courses. JCP&L may want to consider a hybrid program so good use can be made of the excellent facility in Phillipsburg. JCP&L could provide some training at the Phillipsburg facility and not require an Associate Degree. Thus, training would be available to current employees who are interested.

Another issue that came up during the discussions about training was the lack of emphasis placed on training of the journeyman linemen. Those who have been employed for 5, 10, 15 or 20 years need ongoing training. We recommend that JCP&L continue training journeyman linemen and technicians.

Stipulation 32 –

> *"FirstEnergy shall assure that any merger-related staffing reductions in JCP&L's unionized distribution system operation and maintenance group shall be made in conformance with the Board's May 1, 2000 Order (Docket No. EA99070485) and June 6, 2001 Order (Docket No. EX99070483), which require, among other things, that prior to implementation of reductions in unionized transmission and distribution employees, JCP&L shall submit to the Board a detailed study of transmission and distribution work programs, labor hour requirements and gap analysis of reliability requirements versus resource adequacy. That study shall demonstrate that "further workforce reductions will not adversely impact overall reliability performance, including SAIFI, CAIDI, inspection and maintenance schedules and power quality. Additionally, pursuant to the Boards' Order in BPU Docket No. EX99070483, dated June 6, 2001, FirstEnergy shall not offer any enhanced retirement package or plan (VERP, etc.) to JCP&L's service reliability unionized employees (linemen, substation/network employees, etc.) through October 2004."*

JCP&L reported the following New Jersey personnel severances as merger-related staffing reductions. All reductions were in management positions, not unionized distribution system operations and maintenance positions.

Table 38
New Jersey Personnel Severances

Location	Number
Allenhurst	7
Belford	1
Berkeley	2
Dover	2
Farmingdale	1
Freehold	2
Hightstown	2
Morristown	58
Trenton	2
Wharton	1
	78

JCP&L asserts and we support their position that since all of the staffing reductions occurred in the management ranks, a detailed study was not required.

Stipulation 33 –

> *"FirstEnergy is committed to improving JCP&L's reliability and customer service performance. JCP&L shall continue its programs in compliance with the Board's Phase I, Phase II and Phase III Orders entered in its outage and reliability investigations (BPU Docket Nos. EX99100763, EA99070485 and EX99070483), and shall be subject to and follow the Board's Interim Electric Distribution Service Reliability and Quality Standards, set forth at N.J.A.C. 14:5-7. FirstEnergy is committed to working with the Board toward promulgation of appropriate final reliability standards and to supporting JCP&L in its efforts to meet these standards. JCP&L shall follow all other reliability directives from previous Board orders applicable to it. JCP&L shall keep up with its three year reliability improvement work plan as presented to Board Staff and shall complete this program by the end of year 2002, and JCP&L shall maintain sufficient employee and contractor workforce levels to enable it to comply with these commitments. JCP&L shall continue*

> *to meet with Board Staff to review and modify the work plan to assure that the proposed projects are the most appropriate to assure customer reliability. This will allow for adjustments to be made in light of the dynamic nature of the electric system, changing customer needs and developing technology. The plan includes utility infrastructure improvements, such as upgrading of transmission/subtransmission and distribution lines, adding transformer capacities at the substations, installing additional distribution capacitors and conducting circuit reliability analysis. The plan also includes various infrastructure inspection and maintenance programs. JCP&L shall continue its aggressive transformer maintenance program and reporting to the Board consistent with the June 6, 2001 Board Order. JCP&L shall report its CAIDI and SAIFI numbers on a quarterly basis and shall conduct periodic internal audits of its maintenance practices in accordance with the June 6, 2001 Order, and shall provide copies of the audits to Board Staff. JCP&L shall continue its Community Connection Program. JCP&L shall discuss with Board Staff any proposal to consolidate, relocate or close an existing district office (which is an office to which work crews report) in New Jersey prior to implementation."*

The Board's Phase I Order in Docket EX99100763 contained two major communications recommendations:

1. Install fully integrated outage assessment systems.

2. Adopt appropriate communications models for emergency response activities.

All New Jersey utilities were required to implement a fully integrated outage assessment system comprised of Geographic Information System (GIS), an Energy Management System/Supervisory Control and Data Acquisition (SCADA), a software-driven outage management system, and a sophisticated Voice Response Unit (VRU). JCP&L's PowerOn, EMS, IVR, OSI, and 21st Century modules and subsequent improvements and updates meet the recommended technology required in the Phase I order. In addition, based on our review of the actions taken during the July 2003 Barrier Peninsula outages, the communications model for emergency response activities as set out in the Docket EX 99100763 order are being met during emergencies.

Five Technical Recommendations were ordered. Item 1 of the order in Docket No. EX99100763 recommended that GPU continue the circuit revamping program on the top 25% of its circuits in need of improvement based on customer outage minutes. According to the 2002 Distribution Assessment conducted by FE during 2002, JCP&L began to use FirstEnergy's "Circuit Outage Summary by Customer Reliability Index" report to compare data with that of the Worst

Performing Circuit and CAIDI Improvement programs. The "CAIDI Improvement Program" was a supplemental way to target particular circuits for improvement. The Circuit Outage summary by Customer Reliability Index Report will replace the Worst Performing Circuit and CAIDI Improvement Programs as a means of identifying the "worst-performing circuits" in a region. Item 2 required GPU to re-establish the Adopt-A-Circuit program or implement a similar process. JCP&L's current CRI program receives input from its workforce during monthly meetings according to our interviews of the CRI Team members. Item 3 required GPU to pursue a program of SCADA installation on the 34.5 kV circuits in the Northern Region, as well as, increase the installation of three-phase reclosers (minimum of 25 per year) on distribution circuits. A review of the 2001 and 2002 Master Schedule of projects shows the 2001 recloser program equal to 50 installations in each Region, and in 2002, 75 to be installed, split between NNJ and CNJ determined by studies. Item 4 called for installation of 200,000 feet of spacer cable annually for the period 2000-2002. This work was accomplished based on responses to our questions during interviews. Item 5 required GPU to continue to replace and rejuvenate underground cable in light of the reliability problems experienced in Morristown and Summit. Underground cable rejuvenation projects were included in GPU's proposed New Jersey Reliability Improvement Work Plan for 2000 through 2002. On February 19, 2004 JCP&L provided data indicating that the work on the Morristown 5th circuit was approximately 80% completed. The South Street portion of the project is 10% complete. With respect to the Summit Network, JCP&L indicated that upgrades to cables and transformers were approximately 93% complete.

The Board Order in Docket No. EA99070485 contained recommendations designed to improve reliability from the decision-making process down to and including maintenance programs, record-keeping, and restoration performance, all designed to achieve measurable results for improved reliability. GPU was directed to undertake actions to ensure that the utility was fully prepared to handle the stresses on its system necessitated by peak demand periods and to improve restoration. The Board felt that a number of these Phase II order provisions were critical in nature and required further monitoring and evaluation; therefore, on November 28, 2000, the Board retained Schumaker & Company to assist staff in a Phase III project of reviewing and monitoring the implementation of the selected critical Phase II order provisions. Schumaker & Company issued its final report on March 14, 2001, and found that GPU Energy complied with the board Order in Docket No. EA99070485 concerning the six recommendations selected from the original 18 recommendations that the Board had identified as critical. The Board adopted the Shumaker report in its entirety and required additional action by GPU in its Phase III Order. With respect to workforce adequacy, the Board concluded that GPU should not implement any Voluntary Enhanced Retirement Programs or any other layoffs without first petitioning the Board for approval. Although the Board accepted Schumaker's opinion that GPU had complied with the Board Order in Phase II regarding the submission of a CAIDI performance improvement plan, GPU, at Staff's request, established the Community Connections program for certain areas of GPU's service territory that continue to experience inordinate service disruptions. The Board directed Staff to continue to monitor the Company's prioritization and response in the affected municipalities and recommend other activities should the Community Connections Program fail to satisfactorily remedy the situations. The Board, in its Phase III Order, initiated quarterly reports of CAIDI numbers for all districts and all utilities so that appropriate action could be taken should GPU's CAIDI numbers not improve to target levels. With respect to inspection and maintenance, the Board accepted Schumaker's conclusion that although GPU had not met the schedule set out in the Phase II Order, the transformer maintenance program presented by GPU was consistent with programs at other utilities and was a reasonable approach to testing the remaining transformers on the Company's system. The Board ordered GPU to proceed expeditiously with the remaining testing. With respect to transformer maintenance, answers to interview questions indicated that visual inspection of all transformers was completed in June 2000. JCP&L's Compliance Report of October 1, 2001, showed all corrective maintenance orders except 12 had been completed as of September 25, 2001. Action required at 103 locations was to be taken during the next scheduled preventive maintenance for the transformers. The Board agreed with Schumaker that issues involving SCADA and lightning protection at transmission substations were addressed in a reasonable manner. The Board ordered GPU to conduct periodic internal audits of its maintenance practices until the internal auditors were satisfied that the maintenance programs had been fully implemented.

JCP&L provided documentation showing that a total of $62,248,000 was expended during 2000-2002 above the five-year average (1995 through 1996) for systems reinforcement spending. JCP&L did not answer our request to verify that the work included in the Reliability Work Plan was completed. We are unable to verify the projects included in the $62 million expenditure.

Stipulation 35 –

> *"FirstEnergy shall implement its circuit reliability index program in JCP&L's service territory. This reliability index is a blended calculation utilizing CAIDI, SAIDI, SAIFI, substation lockouts, and momentary interruptions ("MAIFI") to evaluate the overall circuit performance. By identifying individual circuits that are not meeting FirstEnergy's standards, analyzing these circuits monthly to identify root causes of the performance, and targeting specific reliability improvement projects where they are needed, FirstEnergy shall focus its reliability efforts in a manner consistent with the expectations of its customers. This program is in addition to FirstEnergy's and JCP&L's commitment that JCP&L shall comply with the Board's Interim Electric Distribution Service Reliability and Quality Standards set forth at N.J.A.C. 14:5-7."*

The CRI program can be a useful tool when combined with long-range planning, system planning, work plans, fuse coordination and sectionalizing studies. It should not be the only tool or the primary tool used to identify whether or not the system is in need of repair or if the system is having problems. The CRI program along with prudent planning should ensure service reliability is adequate. The CRI program is a useful tool and can be used to improve reliability but clearly it should not be the only tool but one of many.

Stipulation 37 –

> *"FirstEnergy shall commit its resources and workforce to directly and quickly address JCP&L storm restoration problem areas on a priority basis over non-FirstEnergy companies."*

Our analysis of JCP&L's response to Hurricane Isabel leads us to believe that for that emergency, FE was in compliance with Stipulation 37. We asked JCP&L if it could be documented that this stipulation was honored during Hurricane Isabel, but they failed to provide an adequate response (they provided a copy of their Final Report on the emergency).

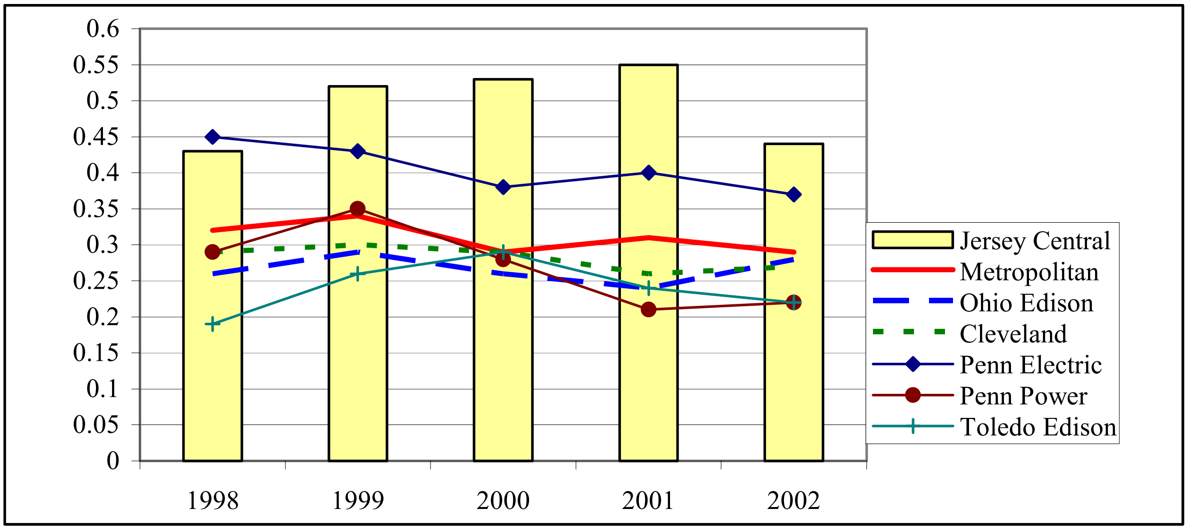
During Hurricane Isabel, restoration work was completed using only JCP&L, Ohio, and contractor crews. No foreign utility crews were requested. We researched the response of other surrounding utilities to Isabel and did not find any evidence that FirstEnergy supplied crews to any other mid-Atlantic utilities. This is the basis for our assumption that JCP&L received priority over non-FirstEnergy companies during this storm restoration.

Stipulation 40 –

> *"New Jersey shall receive at least equal, or where appropriate, additional funding priorities as compared with Pennsylvania and Ohio with regard to electric system upgrades, capital projects, staffing and maintenance programs in the new corporate structure."*

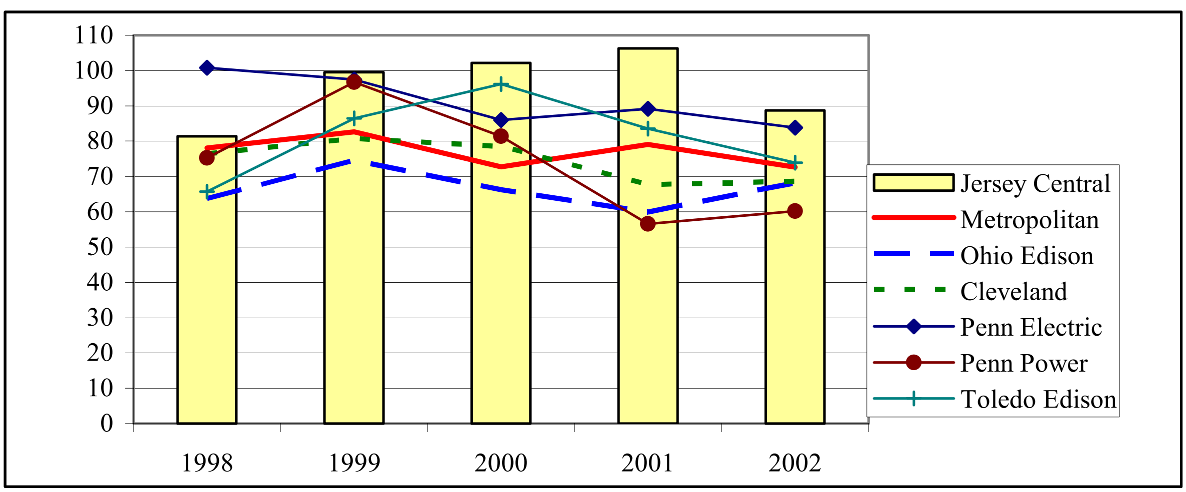
In order to determine compliance with stipulation 40, we have developed a key ratio analysis of selected financial and operating ratios. This analysis is shown in Appendix I and presents data for different categories of operating ratios for JCP&L over a five-year period with comparisons to the other FirstEnergy utilities – Ohio Edison, Cleveland Electric Illuminating Company, Toledo Edison Company, Pennsylvania Power Company, Pennsylvania Electric Company, and Metropolitan Edison. Figure 19 below shows Distribution O&M expenditures on a cents-per-kilowatthour basis for JCP&L and the FE operating companies:

Figure 19
Distribution Operation and Maintenance
Cents per Kilowatthour



On a cents/kWh basis, JCP&L's distribution O&M costs are above those of the other operating companies. A similar trend is shown in Figure 20 for Distribution O&M expenditures expressed as dollars per consumer:

Figure 20
Distribution Operations & Maintenance
Dollars per Consumer



If the JCP&L expenditures shown in Figures 19 and 20 were adjusted to reflect the approximate 24% difference in cost of electrical construction, the cost of

Distribution O&M is generally in line for the FE operating utilities. Figures 21 and 22 show similar analyses for Distribution Plant in Service:

Figure 21
Distribution Plant in Service
Cents per Kilowatthour

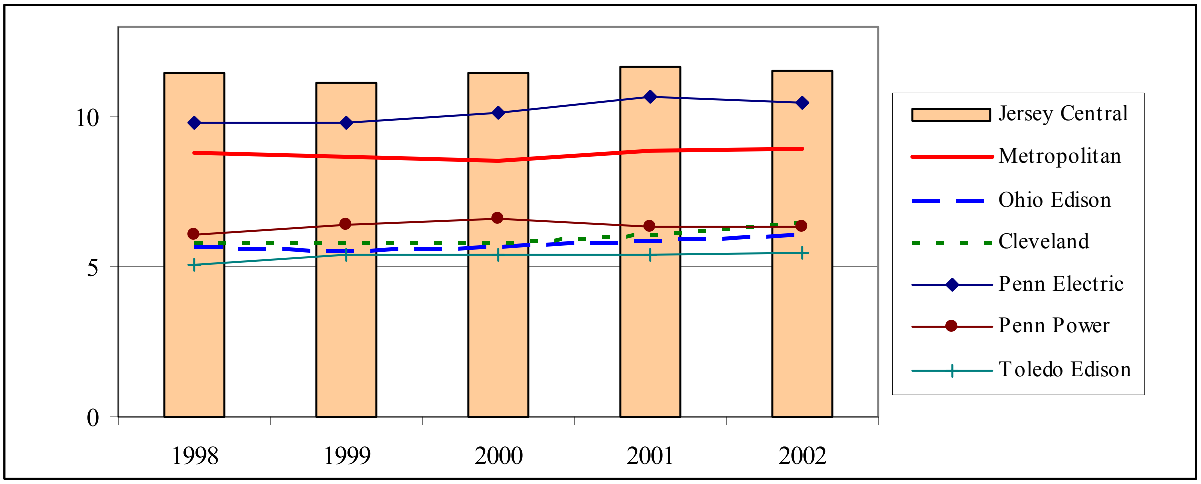
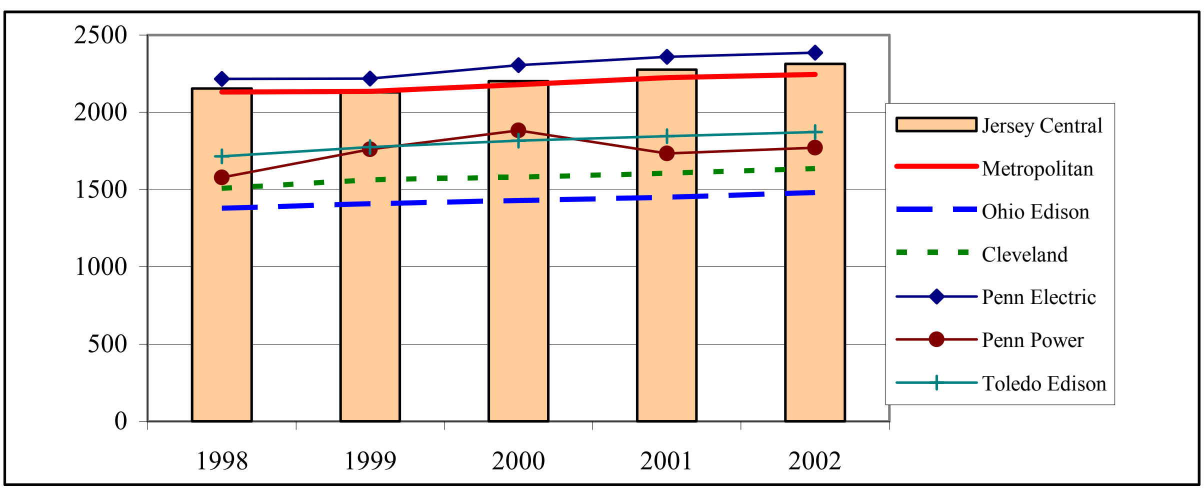


Figure 22
Distribution Plant in Service
Dollars per Consumer



Distribution Plant in Service expenditures for JCP&L, when adjusted for the cost difference between New Jersey and Ohio, are also comparable.

The Merger was finalized in November 2001. It is too early in the merger integration to determine the level of programs FE's management intends to establish for JCP&L in comparison to the other operating utilities. At this point, with respect to bargaining unit staffing, hiring of management employees only and the loss of employees due to attrition, staffing levels have not changed significantly. Based on our analysis, there appeared to be no unusual changes in funding priorities at JCP&L after the merger.

Stipulation 41 –

> *"Within 90 days after merger closing, FirstEnergy shall provide Board Staff with the location of the call centers that will be used for JCP&L customers when calling JCP&L. All call center operations no matter where situated shall be staffed by representatives trained and capable to provide customers with at least the same quality of customer service as they do today. Such representatives shall be trained and be familiar with JCP&L's service territory issues, New Jersey regulations, Board policy, JCP&L tariffs and the New Jersey Customer Choice Program. JCP&L shall notify the Board and Ratepayer Advocate at least 90 days prior to relocation of any such call center."*

During the August 2002 storm event, the Reading call center handled 56,093 total calls. Forty percent of the calls were handled live and 60% using the FE IVR. During the July 4-8, 2003 event, the call center handled 20,336 total calls; 30% were handled live, 69% by IVR and 1% by 21st Century. Staffing levels for the two events are shown below in Table 39:

Table 39
Call Center Staffing

Event Day	August 2, 2002 Storm	July 4-8, 2003 Outage
1	28	20
2	81	46
3	89	36
4	141	229
5	107	186
6	-	170

In each event, the percentage of abandoned calls was less than 1%. During the August 2002 storm, 83% of the calls were answered in 30 seconds. The response rate for the July 2003 Barrier Peninsula event was 71% answered in 30 seconds.

We believe that these statistical comparisons show at least a comparable level of performance during the two events. During our visit and interviews, we were informed that a new call center facility and equipment are scheduled to be implemented in the near future. There should be an investigation in the future to assure that the call center capabilities, staffing, management and commitment are maintained or enhanced beyond the current level.

Addendum Item No. 42 – July 5-8, 2003 Outages on the Barrier Peninsula

Investigation of the July 2003 outages that occurred on the Barrier Peninsula was added to the scope of work for the Focused Audit as an Addendum to the original RFP on July 8, 2003. A special Reliability Master was appointed to conduct a detailed investigation of the July 2003 outages.

During June and July 2003, JCP&L experienced two major events in the communities north of Island Beach State Park and into other sections of Dover Township and in Monmouth County. One event affected 26,000 customers throughout a two-day period during the fourth of July weekend and there were sporadic outages at various times in Seaside Heights, Seaside Park, Lavallette, South Seaside Park, Berkley Township and Ortley Beach and Normandy Beach sections of Dover Township. The other event left thousands of customers in Monmouth Bounty region without electricity.

JCP&L filed an expedited report on July 16, 2003. Booth reviewed and analyzed this report as part of our Focused Audit. The Addendum contemplated that our scope of work related to the Barrier Peninsula outage would include:

1. Review the restoration processes of these outages as well as the crew size used in restoring energy to the service area.

2. Review what steps have been taken to assure that these outages will not occur in the future in the Barrier Peninsula area.

We address Item 1 in detail in Section 9 – *Outage Management*. In general, the Barrier Peninsula outages were not similar to previous major events such as the August 2002 outages or Hurricane Isabel. Multiple faults in the 34.5 kV system resulted in insufficient power being delivered to all distribution substations serving the area. The majority of customers experienced outages because of this lack of power supply, even though the distribution facilities were functioning properly. JCP&L's response to this event involved repair to underwater cable by specialized cable crews, repair to overhead portions of the 34.5 kV system, and resolving distribution equipment problems such as blown fuses and distribution transformers that were caused by the original subtransmission failures.

As part of our analysis, we have reviewed the proposed upgrades to existing facilities and addition of the new circuit from Manitoa as presented in JCP&L's

Accelerated Reliability Improvement Plan. We are in general agreement with JCP&L's proposed plans; however, we do propose some refinements as discussed herein.

It is important that outages, when they occur, should be limited in number and duration. The outages during this period of time have violated both of these premises. The number of outages, as recorded, was beyond the level of acceptability. There were a total of fourteen (14) trouble locations involving both the overhead system and the underground. Additionally, because of the nature of the failures, the time required to locate the problem and the time required to repair the problem equated to outages that were too long and involving too many customers. The conditions leading to these outages are fairly obvious and could have been corrected earlier for a much more economical expenditure. These problems, when they started, just led to other problems occurring, a cascading effect. Below are listed the areas that we believe need to be addressed.

Outages

The outages that occurred on the Barrier Peninsula were not limited to just underground cable failures. There were an equal number of overhead conductor outages also. From the outages on the overhead system, it appears that items such as connectors, switches, or other equipment might be failing. There are things that can be done to help locate these problems and help prevent their failure. These items will generally give off excessive heat prior to their failure. By locating these items prior to their failure, you improve the reliability of both overhead and underground portions of this subtransmission system. The best thing that must be done is the system should be inspected with Infrared Thermography. Infrared Thermography is used to detect hot spots in a utility's electrical components. By scanning this subtransmission system, problem areas can be identified and corrected before they cause system outages such as were experienced on this subtransmission system providing energy to the Barrier Peninsula. This process will identify bad connections, overloaded components, or items that might be defective. When identified, these items should be repaired, replaced, or upgraded as required. By checking the system with Infrared Thermography, maintenance monies can be saved by locating these trouble spots before they cause outages.

As stated in paragraph 13 of the MOU, JCP&L agreed that the Board's Order dated July 16, 2003 required it to complete infrared thermography on the 34.5 kV system serving the Barrier Peninsula and to address identified hotspots. JCP&L represents that it has completed the required thermography and addressed identified hotspots in compliance with such Order.

Additionally, there appears to be a variety of conductor sizes and conductor types being used on these overhead feeds. By using a variety, the capacity of the line is only as high as the lowest rated conductor. It is important that lines as critical as these serving the Barrier Peninsula must have conductors with the same capacity from source to load point, no weak links. These lines should be re-conductored, to not only have similar conductors, but the required capacity to provide a 2nd contingency level of service.

Paragraphs 4 and 16 of the MOU address this finding and recommendation.

Load Related Failures

There were obviously several load related failures to this overhead subtransmission line and quite possibly to one or more of the Underground/Submarine cables. Because of this, the existing lines should be replaced/reconductored or new lines added to provide sufficient capacity to achieve the recommended 2nd contingency level recommended below.

Paragraphs 4 and 16 of the MOU address this finding and recommendation.

Contingency Level

The contingency level for most distribution lines is a 1st contingency; however, there are a number of extenuating circumstances that must be considered with the Barrier Peninsula. Since the Barrier Peninsula has three (3) sources of feed, with a 1st contingency level, this means that the level of service should not be affected by the loss of any one of the sources. The two (2) remaining feeds should be sufficient; however, the Barrier Peninsula area is a heavily populated area and during the time frame from July 5, 2003 till July 8, 2003 experienced unacceptable outages. These outages occurred on both the overhead subtransmission system and the underground subtransmission system serving the Barrier Peninsula. The contingency level should be at a 2nd contingency level. With a 2nd contingency level of service, the Barrier Peninsula should be able to lose two (2) sources of feed and still maintain a sufficient level of service during peak periods. Service to the Barrier Peninsula should be upgraded so that that with the loss of two (2) sources of feed, service will not be adversely affected.

Paragraphs 4 and 16 of the MOU address this finding and recommendation.

Underground/Submarine Cable

The Barrier Peninsula is served from three (3) sources. Two (2) of these sources have a significant section of Underground/Submarine cable in the source. With this Underground/Submarine cable, it is very important to be able to quickly locate and repair any failure that might occur in these sections. It appears, from some of the times recorded on various reports, that the locations of faults on these Underground/Submarine cables are not being effectively located. In addition to the long times required to locate failures, there appears to be a problem with cable repairs. We understand that some of the underground cable is PILC (Paper Insulated Lead Cable) cable. If this is the case, it must be recognized that PILC cable cannot be effectively terminated or spliced on an occasional basis. PILC cable requires considerable skills that must be developed. If a utility does not have a constant need for lead (the metal) cable splicers to hone these skills, they will never develop the skills needed to effectively splice or terminate PILC cable. They would be better off without this cable. What needs to be done with the cable location and repairs is extensive training in both areas. All future cable installations need to make use of EPR or XLPE insulated cable. These types of cables are much easier to splice. In addition, strand fill cable should be used to help prevent water from ingressing into the cables. Finally, there needs to be extensive training done for both the location and repairs of underground cable.

The Board's Order of December 22, 2003 in Docket No. EX03070503 adopting recommendations by the Special Reliability Master addresses this concern by requiring that JCP&L identify and properly store replacement cable as necessary for future repair of the underwater crossing and ensure its availability to any failure site within 24 hours and that it provide additional training for the technicians and their supervisors in the splicing of 34.5 kV paper insulated cables, EPR insulated cables, and any combination of these cables.

Physical Protection of UG Cable

Physical damage has quite obviously occurred to the Underground/ Submarine cables providing service to the Barrier Peninsula. Because of the nature and importance of these cables, as much physical protection as is necessary to provide adequate physical protection for these Underground cables should be provided.

The Board's Order of December 22, 2003 in Docket No. EX03070503 adopting recommendations by the Special Reliability Master and the MOU address these concerns.

Line Sensors

One tool that would be very useful when locating faults in Underground and Submarine cable is the use of line sensors on each cable riser pole. From the reports available, it appears that sectionalizing devices were closed in on underground cable faults several times. When this occurs, unnecessary additional damage is done to the cable. This just increases the expense required to repair the damage. Fault indicators can be used and should be used if nothing else is used; however, a more encompassing solution should be considered. That solution is the installation of line sensors. There are several manufacturers of line sensors that could be used that are very easy to install.

Another problem identified in all of the reports is that of the load flow on the Underground and Submarine cables. Additionally, identifying whether or not the underground cable is faulted is a problem. This being done in an expeditious manner is of the utmost importance. With line sensors you will be able to know the line voltage, line amps, power factor, whether the cable has seen a fault, etc. When these line sensors are used with a data collection device, the information can be gathered at the site of the cable or it can be gathered and sent back to a base location so that the information is instantly available. The use of line sensors will be a very valuable tool in the restoration of power to this area. While all of the discussion here is line sensors on underground riser poles, the use of sensors strategically located on the overhead system is a very valuable tool for monitoring the status and health of the overhead system. Line sensors is also a good recommendation for use on this subtransmission system.

The Board's Order of December 22, 2003 in Docket No. EX03070503 adopting recommendations by the Special Reliability Master and the MOU address these concerns.

Line Protection (Arresters)

Line protection is a preventive maintenance system. Line protection in the form of lightning arresters can prevent system deterioration caused by numerous lightning strikes. These arresters can prevent damage from a large number of direct strikes and nearly all induced strikes. If arresters are located in the correct locations, the effects of lightning can be reduced to effective levels. This is contingent upon arresters connected to grounding which is measured to be 10 ohms or less. The effects of direct strikes can only be reduced to certain levels. The effect of direct strikes can be negated only as far as the arrester can dissipate the lightning energy; however, induced strikes are a different story. Arresters can dissipate nearly all of the energy of an induced strike. Arresters cannot be placed on all structures; however, strategically locating them can greatly improve the outage levels of a line. At a minimum, arresters should be placed at equipment locations, junctions and sectionalizing points. What an arrester does is protect critical equipment from lightning by, in effect, shunting that device out of the path of the lightning energy. Additionally, arresters are useful at shunting low Basic Insulator Level (BIL) poles out of the line and consequently decreasing the outage level of a line.

Paragraph 7 of the MOU addresses this recommendation.

Impulse Levels of Structures

The insulation level of a transmission structure is normally high enough to prevent damage caused by induced lightning strikes. This is because the design insulation levels are high enough to prevent damage due to the induced lightning levels. A typical example of this is the design insulation level of a 110 kV transmission line. These lines are typically designed for 550 kV. This design level is due mainly to the BIL (Basic Insulation Level) rating of the insulators and the sectionalizing equipment. This does not mean that the structure Critical Flash Over (CFO) level and BIL (Basic Impulse Level) are the same as the equipment. The structure BIL is generally much higher than the Insulators or the sectionalizing equipment. This is due to the fact that the structure BIL is a composition of the numerous elements that make up the structure. These elements are composed of various insulating materials, not just the insulators or the insulation of the equipment on the structure. BIL is composed of the insulators, the equipment supports, structure materials, and any other item that might add to the insulation level. In the case of the 34.5 kV subtransmission line serving the Barrier Peninsula, the design insulation level is typically 200 kV. This must be supplemented by other insulation to raise it to an acceptable level to avoid damage or high customer outages from induced lightning surges. We are just talking about induced lightning surges here because they account for approximately 90% of line outages and damage. At a design insulation level of 200kV, outage and damage levels can be high if the Isokeraunic Level is high. The Isokeraunic Level for the New Jersey area, while not as high as the southeast US which has levels as high as 60 – 100, it is at a level of 40 which is still quite high and can cause considerable damage. Because of this the structure design insulation level should be high enough to mitigate the effects of these induced lightning surges. At a BIL level of 350kV, the structure can withstand approximately 95% of induced lightning surges without customer outages or damage to the line. A BIL level of 350kV can be easily achieved by the use of simple insulating equipment and correct placement of grounds and equipment. A minimum structure BIL of 350kV is recommended. At equipment poles, sectionalizing poles, and other low BIL structures the use of lightning arresters should be used. The effective BIL level is only as good as the structure with the lowest BIL.

Paragraph 14 of the MOU, which provides that JCP&L will continue to insulate new 34.5 kV construction of overhead lines at 350 kV Basic Impulse Insulation Level (BIL) as the Company proceeds with system upgrades on the Barrier Peninsula, addresses this finding and recommendation.

Maintenance

This is one area that cannot be compromised when you are talking about a transmission line. These lines are critical in nature and the Barrier Peninsula subtransmission lines are by no means an exception. In order to provide proper maintenance, these lines should be on a set schedule for inspection so as to identify the areas and items that need maintenance. Some items can be assigned a routine schedule for required maintenance.

Temporary Service During Emergencies

When providing temporary service to an area during emergency conditions, it is very important that these temporary conditions meet the same safety requirements of the National Electrical Safety Code (NESC) as lines operated under normal conditions. The temporary underground line placed on the bridge to the

Barrier Peninsula did not meet code and violated numerous NESC rules: Rule 014A3, Rule 320, Rule 321, Rule 352, Rule 361, Rule 362, and Rule 371.

Power Transformers

Our analysis also indicates that five of the six substations serving the Barrier Peninsula have transformers that have experienced all-time peak loads exceeding the transformer nameplate capacity rating These substations include Mantoloking, Ocean Beach, Lavallette, Ortley Beach, and Seaside Park.

In our opinion, it makes no sense to upgrade the present 34.5 kV subtransmission system serving the Barrier Peninsula and not address the overloading of power transformers at the distribution substations. To ensure adequate reliability, additional capacity must be installed prior to the Summer 2004 peak at certain locations. As an alternative, some distribution voltage conversion and load shifting could relieve the transformer overloading condition. The present condition imposes significant risk of an extended outage and possible cascading of transformer failures if improper power restoration actions are taken. The RDO has made a prior restoration error which resulted in an extended outage at the Barrier Peninsula. The present transformer overload condition is an opportunity for similar error leading to extended outage.

Paragraphs 17 and 20 of the MOU which provide that JCP&L will undertake certain transformer diagnostic tests and/or provide certain test results and related corrective actions where necessary, and provide actual measured peak loading data throughout the summer peak season, resolve this recommendation. In addition, as indicated in the Executive Summary, Booth & Associates, together with Board Staff and the Company engaged in an iterative process which made significant progress towards addressing all recommendations and, insofar as the issues discussed above are concerned, to the extent that JCP&L agrees to fully comply with its Asset Management Strategy (AMS) document including the CRI program, which agreement is reflected in the Stipulation of Settlement (which includes the published AMS to which JCP&L has agreed to abide) entered into on June 8, 2004 by JCP&L and Board Staff (and which was reviewed and adopted by the Board), which resolves this recommendation.

RECOMMENDATIONS

There are a number of recommendations for the 34.5kV subtransmission system serving the Barrier Peninsula that need to be implemented as soon as possible. By the summer peak of 2004 if possible. These recommendations are:

1. Contingency level needs to be raised to a 2nd contingency level versus the 1st contingency level currently used.

Addressed by paragraphs 4 and 16 of the MOU.

2. System should be scanned by Infrared Thermography to locate abnormal hot spots and then to correct them as required.

Addressed by paragraph 13 of the MOU.

3. Install line arresters as needed in strategic locations.

Addressed by paragraph 7 of the MOU.

4. Insure that all structures have a minimum BIL level of 350kV. This BIL level equates directly to customer outages levels.

Addressed by paragraph 14 of the MOU.

5. Underground/Submarine cable should, at a minimum, have fault detector installed on the riser poles on each end of the cable. Line sensors would be better.

Addressed by Item 13 in the Board's Order of December 22, 2003 in Docket No. EX03070503, and the work has been reported as complete.

6. In conjunction with #2 above, the line should be inspected in the future on a routine basis and all problems as they are identified should be corrected.

Addressed by paragraph 13 of the MOU.

7. Underground/Submarine cable should be repaired or replaced with cable providing enough capacity to satisfy #1 above. Any cable installed should be strand filled and with additional mechanical protection.

Addressed by Item 8 in the Board's Order of December 22, 2003 in Docket No. EX03070503, and the work has been reported as complete.

8. Most important is the need for training.
   - Training for location of faults on underground and submarine cable.
   - Training for underground/submarine cable repairs.
   - Training for sectionalizing a system such as the Barrier Peninsula system.

Addressed by Items 1, 9, and 13 of the Board's Order of December 22, 2003 in Docket No. EX03070503.

9. Temporary Service During Emergencies. When providing temporary service to an area during emergency conditions, it is very important that these temporary conditions meet the safety requirements of the National Electrical Safety Code.

10. It is recommended that the three transformers located at Mantoloking, Lavallette and Seaside Park be scheduled for replacement by the summer 2004 peak. This recommendation is regardless of age.

Addressed by paragraphs 17 and 20 of the MOU. Also, as indicated in the Executive Summary, Booth & Associates, together with Board Staff and the Company engaged in an iterative process which made significant progress towards addressing all recommendations and, insofar as the issues discussed above are concerned, to the extent that JCP&L agrees to fully comply with its Asset Management Strategy (AMS) document including the CRI program, which agreement is reflected in the Stipulation of Settlement (which includes the published AMS to which JCP&L has agreed to abide) entered into on June 8, 2004 by JCP&L and Board Staff (and which was reviewed and adopted by the Board), which resolves this recommendation.

11. At the Ocean Beach and Ortley Beach Substations, JCP&L has two banks of transformers; one bank operates at a low side voltage of 4.2 kV and the second bank at 12.5 kV. The transformers operating at 12.5 kV are lightly loaded; therefore, it may be possible to relieve loading on the 4.2 kV circuits by converting to 12.5 kV operation and switching load to the second bank of transformers. At Ortley Beach, load was shifted between transformer banks in 2001; however, given the load growth being experienced in the area, the Bank 1 transformer may again be approaching the nameplate capacity; our load data was the 2002 summer peak loading. If conversion is not an economical solution, then the Bank 1 transformers should be replaced immediately or other additional capacity should be added.

Addressed by paragraphs 17 and 20 of the MOU. Also, as indicated in the Executive Summary, Booth & Associates, together with Board Staff and the Company engaged in an iterative process which made significant progress towards addressing all recommendations and, insofar as the issues discussed above are concerned, to the extent that JCP&L agrees to fully comply with its Asset Management Strategy (AMS) document including the CRI program, which agreement is reflected in the Stipulation of Settlement (which includes the published AMS to which JCP&L has agreed to abide) entered into on June 8, 2004 by JCP&L and Board Staff (and which was reviewed and adopted by the Board), which resolves this recommendation.

11. Stray Voltage (Neutral to Earth) Complaints

Introduction

In July and August 2002 several of JCP&L's customers residing in the vicinity of the Herbertsville Substation located in the Township of Brick, Ocean County, complained about experiencing tingling sensations (stray voltages) when attempting to enjoy certain outdoor activities such as use of swimming pools, hot tubs and outdoor showers.

As a result of its own investigation, JCP&L implemented a program that included the installation of 7,000 feet of upgraded neutral distribution wires and additional "down-ground" wires and rods, and adjusted all transformer connections. These efforts reduced the stray voltage levels in some areas but did not eliminate the problem.

On September 26, 2002, Board staff requested the assistance of the National Regulatory Research Institute (NRRI) to investigate the stray voltage phenomenon. On October 4, 2002, they hired VitaTech Engineering, LLC, to investigate the stray voltage occurrences. VitaTech submitted their Report on November 18, 2002. JCP&L reviewed the report and submitted its comments on December 3, 2002, accepting VitaTech's findings and agreeing to implement the report's recommendations. On June 23, 2003 VitaTech personnel revisited the area surrounding the Herbertsville substation and in a letter dated July 26, 2003, recommended additional actions to reduce the "neutral-to-earth voltage" (NEV) further.

Staff requested as part of our Focused Audit of JCP&L that Booth review the report and documentation on the stray voltage complaints in the vicinity of Herbertsville substation and provide additional recommendations deemed appropriate.

Analysis

There have been complaints and problems associated with Jersey Central's electric system contributing to neutral to earth voltage or what is often referred to as "stray voltage". Stray voltage is literally a voltage that exists and can be measured between the neutral of an electrical system and the earth. Humans or animals are subjected to this voltage when standing on the earth and simultaneously touching a water faucet, swimming pool ladder, feeding trough, milking machine or other object at neutral potential This voltage in turn produces a current through a person or animal. The magnitude of current is proportional to the resistance of the individual or animal. Since certain farm animals such as diary cows typically have much lower body resistance than people, the resulting current is much greater and hence animals are more sensitive to stray voltage than humans. Certain conditions such as wet skin from swimming pools or hot tubs reduce skin resistance and increase human sensitivity to stray voltage. This is a phenomenon of electric service in North America and is most often exhibits itself as a customer complaint issue in dairy farming, swine farming, or other agricultural areas with live stock This phenomenon has been a subject of great study analysis, litigation, and engineering and agricultural assessment for mitigation for more than 20 years.

There are many factors that contribute to stray voltage. Some cannot be controlled by the electric utility. Included are soil conditions, rock strata conditions, and extremely rural environments in which electric utility facilities have been expanded with predominantly single-phase facilities. There are also a large array of electric system conditions which contribute to stray voltage. These conditions may exist on the utility system or the customer's system or on both. Conditions on the utility system can be controlled by the electric utility to mitigate stray voltage It should be noted that stray voltage cannot be completely eliminated but can be reduce to acceptable levels.

Stray voltage seems to have a mystique compared to other problems that exist on electric utility systems. Most problems such as excessive voltage drop or overloaded conductors can be easily modeled. The solution can be easily determined and the exact result of a proposed improvement can be calculated. Stray voltage; however, is not easily solved. Usually a number of causes at numerous locations contribute in varying degrees to stray voltage. The solution to stray voltage is the following.

1. Follow a well designed procedure to determine the magnitude of stray voltage.
2. Continuing with the procedure determine whether the stray voltage originates on the utility system or on the customer's system.
3. If the stray voltage originates on the customers system, provide customer with reasonable guidance and refer to an electrician.
4. If the stray voltage originates on the utility system, determine possible causes and list in order of importance.
5. Implement solutions starting with those most likely to result in the greatest mitigation.
6. Repeat step 1 and if necessary step 2
7. Repeat steps 3 and 4
8. Continue the above procedure until stray voltage is within acceptable limits.

The most notable solutions to utility stray voltage are adequate or enhanced system grounding, reduction of the neutral resistance and phase balancing to keep the current on each of the conductors as close to equal as possible and as little current flowing the neutral as practical. Our investigation indicates that Jersey Central's electric distribution power line grounding was periodically found to be poor at best and in some cases is inadequate. The section on system grounding analysis provides information on the earth resistivity and ground grid assessment of the electric distribution lines. Also, there was an assessment of the adequacy of the grounding in the substations. The substation grounding appeared to be adequate and our assessment and investigation of a statistical valid sampling of substations found no ground grid design deficiency or inadequate levels. We did, however, find that the power lines themselves had inadequate ground level and the grounding system was not adequately maintained. There were many broken or damaged ground wires and many of the poles were identified to have not grounding or grounding that had been so compromised it was ineffective. This combined with the inadequate application of lightning arresters and inadequate grounding of the system at arrester locations including bonding of arresters to the grounding and neutral systems results in the increased likelihood that lightning storms will cause ground potential rises and lightning surge and imposition on customer's equipment.

Also over time, new home and commercial construction has moved from 100 percent copper water piping which provided a source of good system grounding for the customer to plastic pipe which provides no additional ground electrode source. This means that both the houses and the electric utility system are not as well grounded today as they have been in the past. Thus, the electric utility systems and the homes must have made grounds in the form of ground rods or counter poises installed and maintained at a substantially more improved level than even 20 years ago. Furthermore, the more sophisticated electronic equipment in homes and businesses result in the perception of a poor ground system because of the higher level of sensitivity.

The increased level of stray voltage complaints can be attributed to the poor condition and maintenance of the electric distribution system and its ground grid combined with the already high resistance of the system grounds ranging from 100 ohms to well in excess of 1,000 ohms per ground location tested. A preferred level would be between 25 to 100 ohms per overhead system and between 10-25 ohms per site tested for the underground system.

Underground electric distribution systems, up until the last ten years, were predominantly installed as direct-buried systems with bare concentric neutrals. This meant that the bare concentric neutrals served as an excellent grounding system as a counter poise. Because of the recognized problem associated with bare concentric neutral deterioration when in contact with earth, the industry moved to a jacket covering the bare concentric neutral. This eliminated the contact with the earth and the concentric neutral deterioration; however, it also eliminated the counter poise effect of the bare concentric neutral. This for new or replacement cable installations combined with the inherent loss of concentric neutral due to cathodic deterioration and attack resulted in substantially poor grounding on the underground electric distribution system over time. This has exacerbated the stray voltage conditions in the entire electric utility industry including Jersey Central. Jersey Central will have to make a concerted effort on a prioritization basis to move towards improving and enhancing its grounding system in order to not only improve system performance, but to mitigate stray voltage conditions. This will take substantial time and capital investment.

RECOMMENDATIONS

Based on our review of the VitaTech Report and the Board orders, we support completion of action items 1-4 identified by Board Order dated November 13, 2003, in Docket No. E002120923 prior to April 1, 2004. We are also in agreement that the monitoring and rebalancing efforts (items 5-8) should be ongoing.

Additional recommendations include the following.

- Use the document "Stray Voltage – Troubleshooting Tips for Electric Utility" as a procedural guide for investigating stray voltage and reducing stray voltage complaints. This document is included as Appendix I and it can also be found at the web site mikeholt.com.
- Patrol all feeders with stray voltage complaints to look for faulty equipment such as blown capacitor fuses in three phase banks, faulty arresters, broken insulators, loose or damaged ground wires, loose or damaged neutral connections. This should include measuring the resistance of neutral connections and splices.
- Record distribution pole grounding resistance at the affected circuits. This measurement is easily accomplished with readily available clamp-on ground resistance testers, such as those made by AEMC or LEM. Additional grounding must be implemented until the grounding resistance is less than 25 ohms.
- Investigate use of soil enhancement materials, such as bentonite clays, at distribution pole ground rods/electrodes to reduce soil resistivity during dry summer conditions.
- Balance loads on three phase lines to fullest extent possible. It is important that phase loads not only be balanced at the substation but throughout the length of the circuit. Converting heavily loaded single-phase taps to three-phase and balancing loads may be required.
- Increase size of neutral conductor if undersized.
- Reduce circuit loading, if possible, to reduce the amount of neutral current flowing during peak loading if the circuits cannot be balanced. This can be accomplished by adding new circuits to reduce the overall load per circuit.
- Investigate circuit(s) for unusual configurations such as alternate return path for neutral current. An example is a natural gas or water line or even the earth that

provides a much shorter return path to the substation, particularly if the circuit is of a meandering nature.

- Consideration of installing isolation (block) devices if state/local codes permit to eliminate the problem at sensitive installations such as swimming pools until a utility system solution is found. Isolation devices are installed between the utility system neutral and the customer (secondary side) neutral per the 2002 National Electrical Safety Code 097D2. This recommendation should be used only after an exhaustive effort to correct the stray voltage problem.

Stray voltage investigation and mitigation is a dynamic process. Several organizations that are leaders in this field are listed below. Since this phenomenon has a strong impact on the diary industry, it is no surprise that states and organizations with strong ties to the diary industry and agriculture are in the forefront of this research. It should be noted that the same techniques that apply to investigation and mitigation of stray voltage in agricultural settings apply equally to urban settings such as residential swimming pools and hot tubs.

Organizations and Web Sites

Midwest Rural Energy Council	www.mrec.org
University of Wisconsin –	www.uwex.edu/uwmril/stray_voltage/svmain.htm
Public Service Commission of Wisconsin	http://psc.wi.gov/electric/newsinfo/strayvol.htm
Electric Power Research Institute	www.epri.com
The National Electric Energy Testing Research & Applications Center	www.neetrac.gatech.edu
Rural Utilities Service	www.usda.gov/rus/electric/index.htm

Notable Publications

Effects of Electrical Voltage / Current on Farm Animals - How to Detect and Remedy Problems. USDA Publication 696

Stray Voltages – Concerns, Analysis, and Mitigation. NEETRAC Project Number 00-092

The Organizations and Web Sites listed above include numerous publications, papers and other documents pertaining to all aspects of stray voltage.

12. Recommendations and Action Plan

Since the July 1999 heat wave event, JCP&L has been in a catch-up mode in terms of improving service to its customers. In response to the Board's Phase I, II, and III Orders, JCP&L committed to accelerate approximately $56 million in reliability expenditures to meet a three-year reliability improvement work plan by the end of 2002. In February 2003, JCP&L initiated the Accelerated Reliability Improvement Plan (ARIP), an internal FirstEnergy commitment to fund approximately $50 million in ten major projects to "compress the time frame" to improve reliability in the Central and Northern New Jersey Regions. Our investigations show that if continued improvement is to be achieved in reliability, JCP&L must complete additional capital and maintenance improvements. Although the Accelerated Reliability Improvement Plan is a good initiative which should not be interrupted for other activity until completed, it must be noted that all items in this plan are typically ongoing customary utility practices.

Booth has developed a comprehensive set of detailed recommendations including associated action plans. These recommendations and action plans have been placed in three priority categories. Priority One are those action items which should be implemented first and should be given the greatest consideration by both the Board of Public Utilities and Jersey Central and FirstEnergy. Priority Two are those action items that are believed to provide for enhancement to the system reliability, operations and safety, which will require a long-term implementation period and which have the same level of significance as Priority One items. Priority Three are those action items and recommendations that should be considered and implemented; they may or may not contribute directly to improved reliability in the near term. However, Priority Three recommendations will have a positive long-term effect. It is extremely important for the Board of Public Utilities to understand that it is Booth's position that its first task, and the main goal of this Focused Audit and the recommendation and action items proposed by Booth, is the improvement of overall electric service reliability to the customers in New Jersey in the most prudent and cost-effective manner. Booth has outlined, as part of what we believe is the very first goal of our Focused Audit, a series of reliability standards and measurement tools to be utilized by the BPU, Jersey Central, and FirstEnergy, to measure the success of the implemented Accelerated Reliability Initiative under way by Jersey Central and the recommendation and action items outlined in our Focused Audit report. **Booth believes it would not be in the best interest of the BPU, the customers, Jersey Central, or FirstEnergy for Booth or the BPU to attempt, on the initial phase of implementation, to micromanage Jersey Central.** We believe it is important for BPU to establish a set of reliability goals, utilizing the recommendations of Booth & Associates, Inc., that will serve as the measurement mechanism to establish whether Jersey Central and FirstEnergy are making the appropriate progress and meeting the required reliability standards expected by the BPU. Booth believes to the extent that Jersey Central and FirstEnergy can meet these reliability goals and standards as recommended and hopefully, be adopted by BPU, it is generally inconsequential as to how this is achieved. Our recommendations, we believe, if implemented by FirstEnergy will assure the greatest likelihood of achieving the reliability goals and standards which we have outlined and recommended in this report. We are recommending that the BPU adopt standards and provide Jersey Central with the latitude of implementing the recommendations and action items in a manner in which it believes is most appropriate to achieve the reliability goals. We believe the BPU should allow Jersey Central a degree of latitude in reaching these goals and in the method in which they adopt the recommendation and action items. We would only find it necessary that the BPU micromanage Jersey Central to the point of forcing the implementation of specific recommendation and action items, potentially including 100% of the action items, to the extent that Jersey Central's reliability improvements are not rapid and dramatic and to the extent that Jersey Central's reliability does not meet the reliability goals within a prescribed time period. Booth recognizes that with any electric utility system, there is a myriad of ways in which to approach reliability enhancement. It is not necessary for Jersey Central to implement 100% of the recommendation and action items in order to achieve acceptable reliability levels. Booth, throughout its report, has documented many serious problems and deficiencies; however, it should be noted that Booth also identified and documented many areas in which FirstEnergy and Jersey Central have made substantial strides and are implementing programs and processes that will clearly improve system reliability. Our recommendations outline those areas where we believe there are deficiencies and where programs and processes either need enhancement or need adoption in order to assure that the reliability goals and measurements that are recommended herein can be met. The BPU should only mandate those other programs upon Jersey Central's failure to meet the reliability standards outlined herein, again re-emphasizing we do not believe micromanagement of an electric utility is necessary. The BPU only needs to review reliability progress and assure its customers that the goals which are established by the BPU are being met. Jersey Central must, however, come in compliance with the National Electrical Safety Code in those areas of deficiency identified in this report.

Priority One Action Items

Our recommended Actions rated Priority One all relate to the period leading up to the summer peak of 2004. The Priority One Recommendations were presented in our Executive Summary for Immediate Recommendations before Summer 2004 filed on January 23, 2004. There are five major areas of concern:

1. Continuation and expansion of the JCP&L current Accelerated Reliability Improvement Plan.

2. Safety concerns needing immediate attention.

3. Recommendations to be completed prior to the summer 2004 peak.

4. Dispatch Center (RDO) and PowerOn data enhancement and outage management procedure documentation.

5. July 5-8, 2003 outages on the Barrier Peninsula.

On March 25, 2004 the Board adopted a Memorandum of Understanding (MOU) that addresses actions that may be of value to improve the reliability of electric delivery for the Summer 2004 peak period. The MOU adopts as recommended or in principle all our Priority One Action items except the following two recommendations from the first and third major areas of concern noted above:

1. The FirstEnergy wood pole testing program for distribution poles adopted for JCP&L should be changed to, at a minimum, a 15-year cycle. The FE program has no periodicity.

2. FirstEnergy does not include retirement of aging transformers in a life cycle program, instead transformers would always be operated to failure. Our recommendation is the requirement to systematically replace older transformers that are in excess of 30 years old utilizing a proper life cycle program over the next 10 years based on full testing and assessment, to avoid possible adverse impacts on reliability.

Therefore, because almost all of the Priority One recommendations, with the exception of the two noted above, have been resolved by the MOU, the following discussion is provided as the support that created the MOU.

1. Continuation and Expansion of the JCP&L Current Accelerated Reliability Initiative

As part of our assessment, we have carefully reviewed and discussed with JCP&L its current accelerated reliability initiative. We characterized this reliability initiative as a good beginning. It should be noted it is our professional opinion that this accelerated reliability initiative only contains those areas of activity that should be standard practice for any electric utility as part of its ongoing business process. All of the accelerated reliability initiatives identified in this program are normal and customary electric utility practices performed on an annual basis by prudent utilities. There is no question that JCP&L should not divert its attention from first completing all of the items identified in its accelerated reliability initiative. Furthermore, these should be practices that are reviewed and updated on an annual basis and should be completed prior to each year's projected system peak demand. We have identified within this accelerated reliability initiative several areas which require expansion in order for this reliability initiative to have the opportunity for maximum reliability enhancement achievement. The areas which should be expanded in this reliability initiative prior to the Summer 2004 Peak are:

RECOMMENDATIONS

(a) The expansion of system-wide sectionalizing equipment should include the installation of fuses or reclosers on all taps exceeding five spans. Our system review indicated that JCP&L has very few fuses on tap lines. Also, our initially limited review of the partial response to Data Request BA-19-1 would indicate the need for more lateral or tap line fuse application. This means that outages as a result of poor right-of-way clearing or other problems on short to medium length tap lines result in major feeder outages when such outages could be mitigated and affect far fewer customers. Also, troubleshooting and outage restoration time will be shortened.

Paragraph 4 of the MOU, which provides, among other things, for JCP&L's continued fusing of certain circuit lateral taps and certain main feeder sectionalizing consistent with JCP&L's circuit protection philosophy, addresses this recommendation.

(b) The protective coordination enhancements should be implemented with a variety of coordination schemes, recognizing the necessity to have different protective coordination methods for industrial circuits and commercial circuits and residential circuits. This is to state that one scheme does not appropriately address the reliability needs for all types of customers. These should include:

- Install tap fuses on distribution taps, particularly troublesome taps, that are five spans or longer, coordinated as follows[1:]

- On industrial circuits, the fuse should blow before operating a major feeder recloser or breaker that would cause a momentary on an industrial customer.

- The fuses should be coordinated on major commercial feeders, particularly those with office complexes such that the fuse will blow before operating the main feeder recloser or breaker.

[1] Most commonly applied in the states.

- On residential circuits, the feeder tap fuses should be coordinated such that the breaker or recloser will operate at least once if not twice on the instantaneous operating curve before the tap fuse blows. This will minimize the number of permanent outages as a result of tree limbs, squirrels or other momentary fault event.

Paragraph 4 of the MOU, which provides, among other things, for JCP&L's continued fusing of certain circuit lateral taps and certain main feeder sectionalizing consistent with JCP&L's circuit protection philosophy, addresses this recommendation.

(c) The GIS Audit process should eliminate the significant time lag in the AM/FM system being available to the RDO and PowerOn. Also, the present duplication of effort and associated time lag of data entry into PowerOn should be eliminated. During the November 5, 2003 interview and demonstration of PowerOn, JCP&L stated that PowerOn circuits are manually built and that the Vision AM/FM GIS information is manually input into the SmallWorld GIS Database residing in PowerOn. It was further stated by Mr. Homsher that he never wanted the transfer to be automated, even though the next version of PowerOn would allow automatic GIS database update.

Paragraph 1 of the MOU, which provides that JCP&L will conduct a GIS field audit and provide status reports with respect thereto, addresses this recommendation.

(d) As part of the Telemetry Enhancements, JCP&L should establish load level alarm points for both the operations personnel at the RDOs and for the planning personnel. There should be clearly established alarms and a set of operating procedures in place at the RDO for reaction to any alarm condition.

Paragraphs 5 and 19 of the MOU, which provide, among other things, for JCP&L's completion of a specific 34.5 kV telemetry project including RDO alarms and for real time monitoring of loads, addresses this recommendation.

(e) The Vegetation Management program and public relations strategy should include a "danger tree" management program. Also, the addition of reclosers or fuses in vegetation management challenging areas should be incorporated.

Paragraph 6 of the MOU, which provides for JCP&L's continued accelerated implementation of FirstEnergy Vegetation Management specifications, which include a "danger" or "priority" tree management component, addresses this recommendation.

(f) Include as part of the 34.5 kV system lightning arrester or overhead static wire program the necessity to achieve 10 ohms or less on all "made electrodes" (ground rods) at the grounding connection points to include every arrester location.

Paragraph 7 of the MOU, which provides that JCP&L will continue to include, as part of its applicable construction standards, the objective to achieve 10 ohms or less on all "made electrodes" (ground rods) at the grounding connection points to include every arrester location with respect to its 34.5 kV system lightning arrester or overhead static wire program, addresses this recommendation.

(g) Include as part of the 34.5 kV Automation program an aggressive published set of maintenance and testing procedures for all components including batteries and controls.

Paragraph 8 of the MOU, which provides, among other things, that JCP&L will review and assess its existing written maintenance and testing procedures for all components of its 34.5 kV system, addresses this recommendation.

(h) The PowerOn OMS upgrade should include the elimination of the duplicated "SmallWorld" GIS data input process.

Paragraph 1 of the MOU, which provides that JCP&L will conduct a GIS field audit and provide status reports with respect thereto, addresses this recommendation.

2. Safety Concerns Needing Immediate Attention

(a) Substation Fences and Grounding Issues

Jersey Central Power & Light Company's practices for grounding substation fences does not meet National Electrical Safety Code (NESC) requirements and industry standards resulting in a safety hazard to the public and to its employees. The design and installation of the ground grid system in a substation is meant to reduce dangerous touch and step voltages to safe levels in the event of a fault in the station. A safe "step voltage" means that the voltage difference between the feet of a person walking across the substation during a fault event will not be at dangerous levels. Safe "touch voltage" means the voltage difference from a person's feet and their point of contact with a structure, fence, or piece of equipment will remain at safe voltage levels during a fault event. Per the ANSI/IEEE Std 80 – IEEE Guide for Safety in AC Substation Grounding [Std 80 Section 16.3] the most dangerous touch voltages occur on the substation fence. For this reason the NESC calls for bonding of the fence and the barbed wire strands at the top of the fence [092.E]. NESC 092.E.4 states "If barbed wire strands are used above the fence fabric, the barbed wire strands shall be bonded to the grounding conductor, jumper, or fence." JCP&L in its past and present practices only connect the fence posts to the ground grid at typically 30' intervals. JCP&L does not extend bonding conductors to the barbed wire at the top of the fence and relies on the fence posts for bonding of the fence fabric. Appendix C contains a copy of the NESC Interpretation Booth relied upon for our determination. Our opinion and our reading of the cited NESC interpretation is that bonding of the barbed wire is required to meet code and not simply a recommendation exceeding the code requirements. JCP&L employees and the public who are in proximity to a substation fence during an electrical fault involving the substation may be subjected to life threatening voltages.

Our examination of JCP&L substations showed three installations were especially troublesome with regard to the safety of the public and JCP&L employees. Two of the installations, Rosemont and Flemington Substations, involved temporary transformer connections along with temporary substation fencing, and at one station, Cheesequake, there was no fence at all.

The disconnection of the old transformer and the connection of the temporary transformer at the Rosemont substation in the Northern Region were done in a manner that poses great risk to the public and to JCP&L employees. High voltage conductors were disconnected from the old transformer and the transformer was left in place; but the transformer's bushings were not grounded per industry standard safety practices NESC Rule 123 and OSHA 1910.269(n). A person standing on the ground in the station could easily touch the transformer low voltage bushings. With the old transformer directly under an energized bus it is very likely that dangerous levels of voltage are stored in the transformer which could be discharged causing injury to a person who comes in contact with the transformer bushings. Grounding all the high voltage bushings in a disconnected substation transformer prevents the build up of unsafe voltages. A temporary fence erected around the temporary transformer was not grounded at all. Only the temporary transformer was grounded to the existing ground grid. The temporary fence without proper grounding could cause serious injury to someone in proximity to the fence if an electrical fault occurred. When these items were pointed out to the supervisor of substation maintenance, he was unaware of the safety hazards posed by the disconnected transformer and the lack of grounding on the temporary fence." Though this is in an isolated rural setting, there is a residence directly across the street and children were observed in the area.

At the Flemington Substation work was in progress that required the installation of a mobile substation. The temporary fencing around the mobile substation had several deficiencies creating dangers to the public and JCP&L employees.

(1) The temporary fencing was not grounded. (NESC and OSHA requirement)

(2) Sections of fence were not joined together securely. (Only one metal clamp and one plastic wire tie were used to join two adjacent fence posts together.)

(3) The fence was installed too close to the mobile substation, which would allow sticks or other objects be inserted through the fence fabric and come in contact with the mobile substation.

Flemington was easily accessed through a local business parking lot adjacent to the substation. The temporary fence at the Flemington Substation would not easily deter unauthorized access into the substation. As described before the lack of fence grounding presents an extreme hazard of unsafe touch voltages involving the temporary fence during a fault condition.

At the Cheesequake Substation no perimeter fence exists around the metal-clad breakers and transformers. Instead a collection of fence partitions located between the switchgear and transformers are used to limit access. There were areas where it would be easy for animals or small children to crawl under the high side metal-clad switchgear, which is mounted on short, raised, concrete piers. Installations such as this may be observed within industrial complexes with perimeter fencing and limited access. It was mentioned that Jersey Central was in the process of clearing the area for the installation of a new perimeter fence surrounding the substation. The risk of unauthorized access to this substation is high without the completion of the perimeter fence.

The problems at the Rosemont, Flemington, and Cheesequake substations were corrected by JCP&L after our Audit brought the problems to JCP&L's attention.

RECOMMENDATIONS

(1) Standard industry practices call for seven-foot (7') fences (including 1' barbed wire) and bonding the fence posts, fence fabric, and barbed wire to the substation ground grid system. We recommend that all substation fences comply with the standard and the fence posts, fence fabric and the barbed wire at the top of the fence be bonded to the substation ground grid conductors at all substations. This additional grounding will help protect the

public and JCP&L employees from dangerous voltages in the vicinity of the substation fence during an electrical fault.

Paragraph 2 of the MOU, which provides that JCP&L will request a rule interpretation from the IEEE, addresses this recommendation.

(2) JCP&L should prepare a safety program addressing correct substation grounding practices, placing emphasis on fencing and transformer grounding. All field and engineering employees, and contract workers should attend this safety class in the year 2004.

Paragraph 9 of the MOU, which provides that JCP&L will address training related to substation grounding design practices for appropriate employees, addresses this recommendation.

(3) JCP&L should assess the adequacy of the substation grounding, counterpoise and perimeter fence grounding at all of its substations utilizing the IEEE standards. JCP&L was unable to direct us to any documentation on prior or existing calculations or tests as required by the NESC and prudent utility practice. Enhancement of substation grounding will not only improve safety, it will also enhance reliability and equipment performance.

Paragraph 2 of the MOU, which provides that JCP&L will request a rule interpretation from the IEEE, addresses this recommendation. Paragraphs 10 and 11 of the MOU (described below) also address aspects of this recommendation.

(4) JCP&L should perform follow up inspections of their facilities to ensure correct grounding practices are followed. The safety problem at Rosemont concerning the out-of-service transformer should be corrected immediately by grounding the bushings.

Paragraph 10 of the MOU, which provides that JCP&L will, among other things, continue to include substation grounding as part of its monthly substation inspection process and will continue to ground out-of-service equipment, addresses this recommendation.

(5) At the Upton substation, a notice was posted on the high-side steel structure stating "Must Wear High Voltage Boots When Switching." When asked what this sign meant, the response was the substation ground grid had been tested and found to have unacceptable touch potentials. This type of testing should be performed at all substations to verify that the existing ground grid is adequate. Based on comments it would appear this was the first substation where it was determined unacceptable potentials could occur for faults. It is recommended that "old" substations with limited ground grids be tested in

accordance with IEEE Std 80 to verify resistance for ground values required for safety and to determine that grounding continuity exists for all equipment grounding connections.

Paragraph 11 of the MOU, which provides that JCP&L will provide a report to the NJBPU Staff about the various methodologies that are available to test the integrity of the ground grid, addresses this recommendation.

(b) Warning and Danger Signs

JCP&L has an adequate number of signs on fences, steel structures, and equipment inside the substations we inspected. However, most of the signs do not conform to the latest sign standards. All new and replacement signs need to be installed in accordance with the latest National Electrical Safety Code (NESC) and ANSI Z535 sign, tag, and label standards. They should also comply with the latest Occupational Safety and Health Standards. The majority of the substations visited did not have signage reflecting these latest standards. It is important that the signs are capable of being easily read and understood and fully comply with the most current editions of NESC, OSHA and ANSI.

Many JCP&L substation signs were prematurely faded, small, and with limited information and effectiveness. Danger stickers on structures are small and the red color around the word "Danger" is faded on those stickers facing east, south, or west. The standards are very specific concerning readability of signal words (message) and viewing distances. Also, it is industry standard practice to place "Warning" signs on the fence, "Danger" signs on structures, and signs with emergency contact information on the gates.

RECOMMENDATIONS

We recommend that JCP&L's new replacement signs be installed in accordance with the latest ANSI Z535 standards and OSHA standards in conjunction with updating their material specifications calling for quality, long-life materials. Twenty-year ratings are available that cover fading and cracking of material. These signs should emphasize action, use proper signal words and colors, show emergency information, and are bilingual if appropriate.

Paragraph 12 of the MOU, which provides, among other things, that as JCP&L replaces faded or cracked or otherwise unreadable warning signs on its substation fences and gates, it will do so with signs that comply with the latest ANSI 2535 and OSHA standards and that all new signs will also comply with the latest ANSI 2535 and OSHA standards, addresses this recommendation.

(c) Pad-Mount Transformers

In our opinion, pad-mount distribution transformers are in need of immediate attention due to violations of the NESC and customary utility practice. Our observations of the underground distribution system revealed that pentahead bolt removal is a significant problem. Apparently, there is a system practice to remove specified and manufacturer-installed pentahead bolt assemblies which are intended for padmounted equipment security and public safety. This assembly is extremely difficult to remove. JCP&L field personnel stated they removed this locking assembly so the padmounted equipment would be easy and quick to open for them. This, of course, means that access by the public is also quicker and easier. In our estimation, approximately 40% of the transformers that were inspected did not have pentahead bolts.

JCP&L has agreed to replace missing bolts in accordance with an MOU agreed upon schedule and approach.

We also observed a condition where JCP&L used a simple seal mechanism as the lock, instead of a secure padlock. This particular JCP&L seal mechanism could be easily opened without any special tool or key, which is clearly an NESC violation (NESC 381.G), as well as a major safety problem that needed to be dealt with immediately. Approximately 40% of the transformers that were inspected did not have pentahead bolts. We are satisfied that JCP&L's in-stock locking device is an acceptable locking device, when applied in combination with the pentahead bolt.

Another problem discovered during our inspections involved absence of the front fiber boards on the high side of the transformers. This is also an NESC violation (NESC 381.G). As indicated earlier, the Company has explained that it does not have many padmount transformers of this design and that it believes that some were manufactured and delivered without the fiber boards. In accordance with the MOU, JCP&L has stated that it will replace any fiber boards that have been determined to have been removed.

Data requests BA-15-1 and BA-16-1 requested the latest maintenance and inspection reports for padmount transformers in the Northern and Central Regions. Included in the response was a Computerized Inspection and Maintenance System identifying the previous process required by JCP&L policy for inspecting padmounted equipment, which was the basis for the submitted records. The document cited that JCP&L policy dictated an annual external inspection be conducted to assure the equipment is secure or locked and the padmount is free of any observable external defects. An internal inspection was required every third year. This Full Inspection requires opening the doors for a thorough examination of the internal electrical and mechanical condition of the equipment.

Based on the 345 test reports Booth received for padmount inspections, the most recent inspection was 1998, with many inspections prior to that year.

JCP&L has noted that its periodicities for its padmount inspection and maintenance are five years for security inspections and fifteen years for field inspection and maintenance.

RECOMMENDATION

During our inspections, pentahead bolt removal was a significant problem. Apparently, there is a system practice to remove pentahead bolts from a padmount transformer for ease of access. This is an NESC violation, as well as a major safety problem. Every padmount transformer needs to be visited and proper pentahead bolts installed. Special priority should be given to school areas and areas subject to high pedestrian and children traffic. We also observed that fiber boards on live front transformers were absent. This problem should also be corrected at the time of inspection. Furthermore, FirstEnergy should immediately place qualified personnel in charge of the JCP&L program for inspecting padmounted equipment. FirstEnergy should also put mid-level management in place that will enforce its stated policy.

Paragraph 3 of the MOU, which provides, among other things, for JCP&L to replace missing pentahead bolts, addresses this recommendation.

Appendix E contains a list of the unsatisfactory underground installations which were identified during the condition assessment process. This list identified forty-nine (49) locations that access to the padmount equipment was restricted. A combination of vegetation and transformers below grade created problems for accessibility, thus possibly extending the time necessary to restore power in the event of an outage on that particular line. The vegetation also created a safe work distance problem for any JCP&L employee having to work on the padmount equipment. Based on the worker safety problem and the impact on outage duration, these locations were classified as Unsatisfactory.

The obvious fix to the issue is removal of the vegetation and excavation of the soil around the padmount equipment. An alternative could be that JCP&L adopt and **strictly** enforce a policy that prior to opening any padmount equipment, all vegetation in front of or restricting the opening of the padmount equipment would be removed if it infringed on the safe working zone for the employee. This alternative would not address the outage duration issue, but would address Booth's concerns for worker safety. Paragraph 3 of the MOU, which provides, among other things, that when Company personnel open a padmount transformer, they will clear vegetation around the padmount transformer to the extent necessary to provide sufficient clearance for the safety of JCP&L's employees, addresses this recommendation.

3. Immediate Recommendations before Summer 2004

(a) Power Transformer Loading

Based on the utility's power transformer database (transmission to distribution), two hundred and sixty-six (266) of the four hundred and eighty three (483) total power transformers are more than 30 years old, with one transformer, the Stewartsville Substation Transformer, that is 52 years old. This aging population presents a serious challenge for the utility as it attempts to meet future demand for electricity and maintain system reliability. Since transformer failure is an eventuality, an action plan must be put in place to reduce the likelihood of transformer failure. The statement "If you cannot measure it, how can you manage it?" is especially true for transformers. Transformers typically show little evidence of problems until it is too late unless steps are taken to identify problems before they become failures.

Based on the transformer data provided for the Central and Northern Jersey Central Regions, 58 substation transformers are operated above their nameplate rating at times, which represents more than 12% of JCP&L's 483 substation transformers. JCP&L subsequently provided, in response to data request SRM-44-3, information that indicates that measures have been taken, or are in process, to provide load relief for all but 24 of the 58 transformers noted for the 2004 peak period. The typical actions include load transfers, substation upgrades or additions or offloading to mobile transformers. Thirty-nine (39) of these fifty-eight (58) transformers have been in service for over thirty (30) years. Age is not the single factor dictating transformer replacement. It is, however, a very important factor for establishing a replacement program.

To operate above nameplate, it is imperative that steps be taken to ensure that the transformer is not operated at temperatures greater than those allowed for the condition of the transformer and allowed by the transformer standards. (ANSI-C 57.91 - 1995). Operating above nameplate requires that proper precautions be taken to identify those transformers that are at risk of developing problems. A strategic life cycle transformer management program must be in place to establish loading limits.

Paragraphs 17, 18, 19 and 20 of the MOU address specific substations and or transformers and provide an increased focus on monitoring and data collection and assessment. We believe that this represents a very positive step towards addressing some of the concerns we have otherwise expressed in this report about the Company's transformers.

RECOMMENDATIONS

It is recommended that the utility adopt a substation life cycle transformer management program, starting immediately with the previously overloaded transformers and:

(1) Consisting of an engineering review of all of the transformers on the system,

(2) Performing a condition analysis for each transformer,

(3) Strengthening the maintenance program by benchmarking all oil and diagnostic testing to detect abnormal conditions early, and

(4) Establishing a company loading policy that is good utility practice.

Implementing these recommendations, JCP&L will be able to extend transformer life and make informed decisions as to when to replace existing transformers before a costly failure and seriously extended outages. Given the utility's practice of regularly overloading its transformers, and the overall age of the transformers, the utility needs to prepare for losing many of their 30+ year old transformers within the next ten years. Thus, it is imperative that an action plan be established to replace these older transformers. Therefore, it is recommended that:

(1) The utility budget and purchase new transformers for replacements each year over the next ten years, based on full testing and assessment.

(2) The utility implement a life cycle transformer management program.

JCP&L has nine (9) transformers more than 50 years old that need to be replaced immediately and forty-seven (47) that are in the 40 to 50 year age bracket. They should be given immediate attention given their increased possibility of failure due to age. To the extent any of these transformers appear in Tables 7 and 8 in Section 2, they should receive first priority for replacements. For the remaining transformers shown in Tables 7 and 8, load transfer or load sharing should be used to the extent possible to relieve overloading.

Paragraphs 17, 18, 19 and 20 of the MOU, which address specific substations and or transformers that are found in Tables 7 and 8 and provide, among other things, an increased focus on monitoring and data collection and assessment, address this recommendation.

(b) Subtransmission and Distribution Infrastructure

Booth conducted a field condition assessment of a portion of the subtransmission (34.5 kV) system, overhead distribution system, and underground distribution system. The condition was identified by Booth staff as New, Good, Average, Poor, or Unsatisfactory. Once the data was compiled, a second assessment was completed by field staff and our management team. The results of our second assessment which was part of our quality control and review process are included in Appendices B, D and E, identifying unsatisfactory facilities that need immediate attention.

RECOMMENDATIONS

Booth recognizes that it is impractical to have an electric system in which the condition of all the facilities is average or better. However, any facilities that are unsatisfactory as identified in Appendices B, D and E should be corrected promptly.

In addition, there are certain items which should be completed prior to the summer 2004. However, it is realistically not practical or possible to address all these items in less than six months; therefore, JCP&L must put forth its best effort on the most critical items.

(a) Every red tag wood pole in the system should be replaced. The FirstEnergy wood pole testing program for distribution poles adopted for JCP&L should be changed to, at a minimum, a fifteen-year cycle, the GPU standard previously used, beginning in 2004. All current red-tagged poles should be replaced by the summer of 2004. During the inspections conducted in 2004, all poles red-tagged should be removed and replaced within six months.

(b) For joint-use poles owned by JCP&L, JCP&L should immediately inspect the poles for proper size class and proper guying based on attachment loading. All make-ready design changes that should have been identified prior to attachment of CATV and telephone lines should be identified and proper action taken to support both the electric utility and telecommunication uses. Paragraph 15 of the MOU, in which JCP&L makes certain commitments with respect to its assertion and enforcement of joint-use pole rights and obligations, addresses this recommendation.

(c) For joint-use poles owned by the telecommunications company, JCP&L should immediately inspect and cause to be replaced all rotten poles. Also, the recommendations of (b) above should be followed on these poles.

The pole ownership **does not** change the need for recommended pole replacement. JCP&L must take the leadership role in causing unsatisfactory poles to be replaced. The greatest public and employee hazard is associated with the electric utility lines. The owner of the pole is responsible for paying for its replacement if it represents a hazard.

Paragraph 15 of the MOU, in which JCP&L makes certain commitments with respect to its assertion and enforcement of joint-use pole rights and obligations, addresses the recommendations in this paragraph of the report.

JCP&L, NJBPU, and other utilities will need to develop a documented procedure. In the meantime, JCP&L should place the owning party on notice, giving them a short period of time to replace the pole. If not replaced, JCP&L should replace the pole and take ownership with all the rights and obligations.

Paragraph 15 of the MOU, in which JCP&L makes certain commitments with respect to its assertion and enforcement of joint-use pole rights and obligations, addresses this recommendation.

(c) Vegetation Trimming – Northern Region

In the Northern JCP&L Region, "non-preventable trees" is listed as the highest (23%) general cause for interruption events and also the highest (34%) general cause for customer minute duration. It is standard practice to reduce the trimming cycle in major urban and metro areas, as well as, historical districts when municipal or other restrictions contribute to the need for more frequent trimming. "Non-preventable trees" is a misnomer. A *Danger Tree* is defined as any tree or portion of a tree that is outside the normal vegetation trimming or management area that is in extremely poor condition and represents an immediate or imminent danger to the power line, particularly during a storm event. Danger trees should be selectively removed when standard pruning and trimming do not remove a hazard. JCP&L should shorten the trimming cycle in areas that are not trimmed 15' on each side of the pole line to address this major cause of customer outages. There must also be a provision for removal of "Danger Trees."

Paragraph 6 of the MOU, which provides for JCP&L's continued accelerated implementation of FirstEnergy Vegetation Management specifications, which include a "danger" or "priority" tree management component, addresses this recommendation.

4. RDO and PowerOn Enhancements

During the interview and Booth review process, we determined that JCP&L has an extremely cumbersome procedure for assuring that field upgrades and changes and additions are ultimately reflected in their AM/FM mapping system and in PowerOn and their outage management system. As we understood what we heard, typically, it takes six weeks for a field change to be reflected in the AM/FM mapping system. This change is then manually inserted in the PowerOn system by a single individual taking this data, once available, and putting it into the SmallWorld GIS system that drives the PowerOn program and the outage management and predicted modeling system. This can take an additional six to eight weeks and possibly longer. This means there can easily be three or more months of time lag between a change made in the field and that change being reflected in the PowerOn system and the outage management and predictive modeling system. Furthermore, Booth was unable to determine that these changes were reflected in a timely manner at the RDO. Since FirstEnergy and JCP&L rely so significantly on its call center, the data input, the PowerOn system, and its outage management system for predictive modeling and for power restoration procedures, it is imperative that JCP&L immediately correct this enormous time lag. Booth is convinced, both from the apparent lack of timeliness of power restoration after call center data notification, and based on direct involvement with other major power outage situations involving the same flow of data and systems, that the Regional Dispatch Operator and the EMS system are operating with continually and substantially deficient information and can often be receiving information through the PowerOn system and the outage management and predictive modeling of outages that can be substantially in error. Furthermore, there is virtually no quality control program in place to assure that the changes in the field and reflected in the AM/FM mapping system are then correctly reflected in the PowerOn system and in the SmallWorld GIS. As to the quality-control steps, these manual steps should be performed in approximately 1 hour per circuit. If properly implemented, they are useful to assure that the PowerOn system is always operating with up-to-date and correctly-modeled circuit data.

Paragraph 1 of the MOU, which provides that JCP&L will conduct a GIS field audit and provide status reports with respect thereto, addresses this recommendation which is based on this finding.

Booth's evaluation of the RDO indicated several deficiencies which will hopefully be rectified when the RDOs are relocated to each region and again in full operation as regional RDOs in the state of New Jersey. The deficiencies identified at this time include the RDOs' utilization of a MIMIC panel which does not reflect the actual conditions of the electric system. The staff at the RDO admitted that the MIMIC panel was not completely accurate and was generally not used. Even to the extent that the RDO staff indicates that it utilizes the computer, one-lines and screens, it is confusing and can lead to serious problems if there is a complete wall which is supposed to reflect the electric system that is inaccurate. This situation should be immediately rectified as JCP&L moves to Regional Dispatch Offices. Additionally, there are very few alarms which are established and provided for the RDO staff. JCP&L should carefully evaluate all past outages and operations deficiencies at the RDO and install alarms to help mitigate operating errors. Appropriate alarms for loading, as an example, would mitigate the likelihood of load shift that will burn down conductors. Had such alarms been in place, it may very well have mitigated the magnitude of the Barrier Island outage. Additionally, there appear to be few if any written operating procedures for critical switching, including but not limited to the autotransfer schemes and how to maximize their utilization. Training appears to be progressing satisfactorily with the new staff that will be involved in the two Regional Dispatch Offices to be operated independently in New Jersey. There does not, however, appear to be a clear and defined retraining program that in particular is tied into debriefings after major outage events.

RECOMMENDATION

It is imperative that prior to the summer of 2004, that JCP&L correct this deficiency in double entry and slow entry duration. Furthermore, JCP&L needs to correct the deficiencies and problems which exist in data at the RDO that does not appropriately reflect field information. This is particularly critical in the area of equipment availability, circuit availability, and circuit loading capability, opening points, and system sectionalizing. For such data to have upwards of a three month delay in the system must be corrected immediately and should be done during the GIS Audit process of the Accelerated Reliability Initiative.

Paragraph 1 of the MOU, which provides that JCP&L will conduct a GIS field audit and provide status reports with respect thereto, addresses this recommendation.

Based on Booth's observations and interviews, we recommend the following four major actions be assured by JCP&L when the Northern and Central Regional Dispatch Offices open and become fully operational.

1. A MIMIC panel if utilized should fully reflect the electric system and should be maintained in an as-built manner, with the MIMIC panel being modified and corrected to reflect the electric system as it exists.

   Paragraph 1 of the MOU, which provides that JCP&L will conduct a GIS field audit and provide status reports with respect thereto, addresses this recommendation.

2. JCP&L should develop a series of alarm points which will help guide the staff and substantially mitigate operating errors, particularly as relates to overload conditions.

   Paragraphs 1 and 5 of the MOU, which provide that JCP&L will continue and complete a specific 34.5 kV telemetry project and conduct a GIS field audit and provide status reports with respect thereto, address this recommendation.

3. For all switching equipment there should be written procedures that are followed. These procedures should include as a minimum the manner of operation under normal conditions and the manner of operation under each

of the possible emergency conditions, with the development of a failsafe outage mitigation plan.

Paragraph 5 of the MOU, which provides that JCP&L will continue and complete a specific 34.5 kV telemetry project and requires the development of certain written operating procedures, addresses this recommendation.

4. JCP&L should include as part of its training procedures, both a periodic retraining and a developmental training process as part of a comprehensive debriefing to take place after each outage event.

   Paragraphs 1 and 5 of the MOU, which provide that JCP&L will continue and complete a specific 34.5 kV telemetry project and conduct a GIS field audit and provide status reports with respect thereto, address this recommendation.

5. July 5-8, 2003 Outages on the Barrier Peninsula

Investigation of the July 2003 outages that occurred on the Barrier Peninsula was added to the scope of work for the Focused Audit as an Addendum to the original RFP on July 8, 2003. Our Engineers have investigated the events and have had discussions with the Special Reliability Master concerning his investigation. We have reviewed Mr. Downes' Interim Report filed on December 16, 2003 and are in agreement with his recommendations. In addition, we make the following recommendations:

(a) The 34.5 kV system serving the Barrier Peninsula should be scanned by Infrared Thermography to locate abnormal hotspots and the appropriate corrective actions taken as required.

(b) Insure that all structures have a minimum BIL level of 350 kV.

(c) If a temporary service is required during emergency conditions, it is important that equipment used during these temporary conditions meet the safety requirements of the National Electrical Safety Code. The temporary line installed across the Route 37 bridge does not meet NESC Rule 014A3, 320, 321, 352, 361,362 and 371.

We also agree with JCP&L's proposed upgrades to existing facilities and addition of the new circuit from Manitoa as presented in JCP&L's Accelerated Reliability Improvement Plan.

We recommend an additional action be taken prior to the 2004 summer peak to increase the availability of transformer capacity in the Peninsula service area. Our analysis indicates that five of the six substations serving the Barrier Peninsula have transformers that have experienced all-time peak loads exceeding the transformer nameplate capacity rating. These substations include Mantoloking, Ocean Beach, Lavallette, Ortley Beach, and Seaside Park.

JCP&L should both upgrade the present 34.5 kV subtransmission system serving the Barrier Peninsula and address the overloading of power transformers at the distribution substations. To ensure adequate reliability, additional capacity must be installed prior to the summer 2004 peak at certain locations. As an alternative, some distribution voltage conversion and load shifting could relieve the transformer overloading condition. The present condition imposes significant risk of an extended outage and possible cascading of transformer failures if improper power restoration actions are taken

Specific associated recommendations have been addressed by Paragraphs 13, 14 and 16 of the MOU.

RECOMMENDATIONS

It is recommended that the three transformers located at Mantoloking, Lavallette and Seaside Park be included as part of the 27 new transformers we have recommended to be scheduled for replacement by the summer 2004 peak. This recommendation is regardless of age.

At the Ocean Beach and Ortley Beach Substations, JCP&L has two banks of transformers; one bank operates at a low side voltage of 4.2 kV and the second bank at 12.5 kV. The transformers operating at 12.5 kV are lightly loaded; therefore, it may be possible to relieve loading on the 4.2 kV circuits by converting to 12.5 kV operation and switching load to the second bank of transformers. At Ortley Beach, load was shifted between transformer banks in 2001; however, given the load growth being experienced in the area, the Bank 1 transformer may again be approaching the nameplate capacity; our load data was the 2002 summer peak loading. If conversion is not an economical solution, then the Bank 1 transformers should be replaced immediately or other additional capacity should be added.

Paragraphs 17 and 20 of the MOU which provide that JCP&L will undertake certain transformer diagnostic tests and/or provide certain test results and related corrective actions where necessary, and provide actual measured peak loading data throughout the summer peak season, address this recommendation.

Priority Two Action Items

Priority Two action plans are longer-term recommendations designed to improve reliability. If these recommendations are adopted, JCP&L's reliability improvements will meet our recommended system and component performance criteria within the suggested five-year time frame. Priority Two Action items include:

1. Adopt objective performance standards.
2. Replace transformers annually for next 10 years.
3. Implement maintenance programs to correct infrastructure.
4. Increase the number of circuit feeders by approximately 50%.
5. Implement additional lightning protection.
6. Establish substation maintenance and monitoring programs to implement transformer life cycle program.
7. Establish work order inspection program, including addition of Engineering, Inspection and Construction Observation Staff.
8. Implement recommendations for planning studies and standards.
9. Correct loading problems that prevent automatic load transfer procedures from operating as designed.
10. Implement stray voltage recommendations.
11. Systemwide Sectionalizing Enhancement.

1. Recommended Performance Standards

Our recommended Performance Standards consist of two parts – (1) System Overall Standards for CAIDI, SAIDI, and SAIFI and (2) System Component Performance Standards. The present 10-year historic average benchmark used in the Interim Electric Distribution Service Reliability and Quality Standards should be replaced with more objective standards. In addition, JCP&L should meet component performance standards for the following:

(a) Substations
(b) Feeder circuits
(c) Underground circuit faults
(d) Overhead conductor standards
(e) Minimum and maximum voltage levels
(f) Power Factor
(g) Power Quality
(h) Facilities Connections Requirements

RECOMMENDATIONS

Action will be taken if system reliability indexes excluding major events exceed the following:

CAIDI – 1.3 hours
SAIDI – 1.5 hours
SAIFI – 1.0 interruptions

Major Event redefined as: a major storm including winds in excess of 50 miles per hour for 60 minutes or more, wind gusts in excess of 70 miles per hour, ice accumulation of ½ inch or more, hurricanes (declared disaster), snow accumulation in excess of 3 inches, or the proposed IEEE revised definition to be published in 2004.

System components must meet the following standards:

A. Substation Capacity

1. When actual load reaches 95% of nameplate transformer capacity, JCP&L shall develop and budget a remediation plan composed of one of the following actions:

   (a) Replace transformer
   (b) Add transformer capacity in substation
   (c) Shift load so that the transformer is less than 80% loaded based on nameplate rating
   (d) Shift load to a new transformer.

2. When actual load reaches 110% of the nameplate rating, implement the remediation plan within 90 days.

B. Feeder Circuits

All of JCP&L's circuits will be classified into one of the following types of feeders that must meet the following criteria:

1. Industrial

(a) Defined as any circuit that serves at least one customer with a peak load of ≥ 1,000 kW or uses more than 5,250,000 kWh per year.
(b) Action is required when the circuit CRI exceeds 80 or momentary outage for any industrial customer exceeds five per year.

2. Commercial

(a) Defined as any circuit that serves ten or more customers using over 680,000 kWh per year.

(b) Action is required when the circuit CRI exceeds 100 or momentary outages exceed 20 per year per feeder or the SAIDI is ≥ 1.5 hours per feeder.

3. Urban – Residential

(a) Defined as a circuit operating at 300 amps or more normal peak or customer average use greater than 1,200 kWh per month.

(b) Action is required when the circuit CRI exceeds 100 or momentary outages exceed 30 per year per feeder or SAIDI ≥ 3.0 hours per feeder.

4. Rural – Residential

(a) Defined as a circuit operating at less than 300 amps per phase per feeder annual peak or average customer use less than 1,200 kWh per month or average of 20 customers per mile.

(b) Action is required when the circuit CRI exceeds 130 or momentary outages exceed 40 per year per feeder or SAIDI is ≥ 5.0 hours per customer or feeder per year.

C. UG Faults

1. Any section of underground cable experiencing more than two faults due to cable degradation in two years excluding dig-ins or other external damage shall be replaced.

2. Any underground cable with exposed concentric neutral exceeding 15 years age shall be tested every three years to assess the condition of the concentric neutral. If the original installed standards are not met, the cable sections shall be replaced.

D. OH Conductor Standards

Overhead conductors shall not be operated in excess of the following standards:

1. Distribution voltages – current loading using 167° F normal design, 2 fps wind velocity, 35° C ambient and sun. For load transfer, 200° F emergency.

2. 34.5 kV local transmission – all network operating conditions must contain single contingency planning. Current loading at 212° F normal design, 2fps wind velocity, 35° C ambient and sun.

E. Min/Max Voltage

The minimum and maximum service voltages shall meet the Electrical Power Systems and Equipment Voltage Rating (60 Hz) specified in ANSI C84.1-1995.

F. Power Factor

JCP&L shall maintain lagging power factor at 99% in June-September and December-March, and 96.5% at other times at all distribution substations measured at the high side terminals of each transformer. Leading Power Factor during non-peak periods should not exceed 98%.

G. Power Quality

JCP&L shall meet all requirements for IEEE-recommended practices and requirements for harmonic control in electrical power systems, IEEE Standard 519-1992 Section 10 – Recommendations for Individual Customers and Section 11 – Recommendations Practices for Utilities.

H. Facilities Connections Requirements (FCR)

JCP&L shall meet or exceed the FCR published by PJM.

2. Annual Replacement of Transformers

Given the utility's practice of overloading their transformers and the overall age of the transformer stock, JCP&L needs to prepare for losing many of their 30+ year old transformers within the next ten years.

RECOMMENDATION

In order to replace transformers in an orderly manner before failure, JCP&L should budget and purchase twenty-seven (27) new transformers for replacements each year over a ten-year period. Total cost for 266 transformers is estimated to be $133 million, assuming an average cost of approximately $500,000 per replacement.

3. Maintenance Program to Correct Overhead and Underground Infrastructure

Booth believes that its condition assessment has identified the poor distribution infrastructure condition as one of the leading causes for Jersey Central's system reliability. Booth performed an extensive condition assessment. This condition assessment was initially performed based on a randomly selected set of circuits, including a list of worst circuits provided by Jersey Central and a randomly selected set of circuits. Upon completion of this initial set of circuit evaluations, Booth then performed an additional condition assessment after asking Jersey Central to provide a list of the "best of the best circuits." Booth's condition assessment was performed in a manner intended to provide the fairest evaluation and the most reasonable assessment of the electric utility system that could then be used as a proxy for the entire Northern Region and Central Region. Booth laid this methodology out in the initial contract and it was agreed upon by all parties as a reasonable methodology for a condition assessment and was an acceptable method for evaluating the Jersey Central system. This was accepted in the contract and at that time Jersey Central did not complain about the validity of the methodology. Booth went on to improve the methodology through requesting from Jersey Central a list of the "best of the best circuits" such that Booth could include these circuits in the assessment. Within our report we have extensive discussion of our condition assessment, a significant write-up and pictures on the condition assessment in appendices. All of this, combined with our quality control evaluation and internal evaluation has resulted in the development of the recommendations associated with improvement of the electric distribution system infrastructure. Booth has determined and is of the opinion that the Jersey Central electric distribution infrastructure is below average. In order to improve system reliability, Booth strongly recommends that Jersey Central bring its electric distribution system on a median assessment basis up to at least average. This means that there will be some system remaining below average, but it will be offset by system that is above average, in the "good" and "new" range. Since it is impractical to expect any electric utility to have 100% of its system at an average level or better, our recommendations are predicated on the premise that Jersey Central will bring the overall rating of its system up to average.

The following is a summary of the components that must be corrected in the order of prioritization of the corrections:

(a) Systematically replace rotten poles. Assure, as part of the rotten pole replacement program, that there are clear procedures in place for joint-use poles owned by other utilities to be identified and replaced by those other utilities or for Jersey Central to make such replacement and to be fully reimbursed for all engineering, construction and overhead costs associated with such replacements.

To the degree that this recommendation addresses joint-use poles, that subject and this recommendation have been addressed by Paragraph 15 of the MOU.

(b) Install adequate guying and anchors as required by FirstEnergy standards and the National Electrical Safety Code.

(c) Replace all rotten and defective crossarms and deficient poletop assemblies.

(d) Eliminate or otherwise reinforce all pole extensions, particularly those with primary distribution attached that do not meet the transverse loading strength requirements of the National Electrical Safety Code.

(e) Install system grounding consistent with the results of the lightning protection and grounding study which has been recommended.

With respect to the 34.5 kV system, Paragraph 7 of the MOU addresses this recommendation.

(f) Replace all faulted underground cable such that loop feed capabilities are reestablished where loop feed construction existed prior to faulted sections being left unrepaired. This could be accomplished by JCP&L controlling the process through its dispatch switching orders and issuance of repair orders.

(g) Develop a program of expanding the underground distribution system such that all underground distribution serving or having the potential to serve twenty-five or more customers have a loop feed design.

(h) Implement a conductor replacement program replacing all old conductors that have shown signs of multiple failures through being spliced multiple times; that is, fifty-year old or older copper weld/copper conductor or other old steel conductor or aluminum conductor with steel reinforcing that is aged fifty years or greater and has more than three splices per span.

(i) Institute an underground cable replacement program which focuses on cables which have experienced two or more failures due to cable degradation in a five-year period and cables which have been determined to have lost all or a substantial portion of the bare concentric neutral.

The purpose of our condition assessment was to use a sample inspection of facilities that could be extrapolated to the overall JCP&L system. Our cost estimate for performing the necessary repairs and maintenance of the subtransmission system is shown on Table 1 in Appendix B. The estimate to correct the overhead distribution system is shown in Table 2 in Appendix D. The estimate to correct the padmount transformers based on our sample condition assessment is shown in Table 3 in Appendix E. The following is additional discussion concerning each distribution system infrastructure category and the recommended procedure and schedule.

RECOMMENDATION

Subtransmission 34.5 kV

JCP&L should complete an assessment of all deficiencies identified by Booth within 12 months. This assessment must be completed by an engineer or technician that has the training to not only evaluate the physical condition of the equipment, but also know the standards and appropriate applicable code requirements. Based on Booth's inspection and extrapolating to the entire system, approximately 625 poles per year may need corrective action. JCP&L should take this into account as part of its current inspection cycle. All facilities found to require corrective actions should be replaced or repaired within three years based on priorities set by JCP&L. An inspection by an experienced engineer or technician should be done after repair work to assure quality control.

Distribution Overhead

JCP&L should complete an assessment of all deficiencies identified by Booth within 12 months. This assessment must be completed by a trained engineer or technician that can meet the criteria expressed with the subtransmission assessment. Based on the Booth inspection and extrapolated to the entire system, approximately 50,000 poles may need replacement or significant upgrade. JCP&L should take this into account as part of its current inspection process.

JCP&L should set an aggressive schedule to make necessary improvements. Improvements should be completed within eight years. An inspection of the repair work should be completed by an experienced engineer or technician to assure quality control.

Distribution Underground

JCP&L should complete an assessment of all deficiencies identified by Booth within 12 months. This assessment, as previously mentioned, must be completed by a trained engineer or technician. Data responses submitted to Booth & Associates stated that the JCP&L Padmount Equipment Inspection Program had an annual external inspection and a complete internal inspection every three years. Follow-up communication from JCP&L stated inspection practice is 5 years external and 15 years internal. Based on the problems identified by Booth's inspections, a complete external inspection should be completed within 12 months and the previous one-year external and three-year internal inspection process should be utilized in the future. All necessary improvements identified by the inspections should be completed within three years. After completion of repairs, an inspection by a trained engineer or technician should be completed to assure quality control.

Paragraph 3 of the MOU addresses this recommendation.

JCP&L should discontinue the practice of providing radial underground primary feeders for subdivisions serving 40 or fewer customers. Any underground primary serving or having the potential to serve twenty-five or more customers should be designed to have loop systems or alternate feeds. Existing loop feed sections that have failed and not been repaired should be placed on a one-year repair schedule. Existing loop underground lines that experience a "burnout" should be repaired as soon as practical and placed back in service.

4. Increase the Number of Circuit Feeders by at Least 50%

Reducing circuit loading on the JCP&L system would greatly reduce the number of customers affected by an outage, as well as provide additional capacity for switching and load shifting during emergency conditions.

RECOMMENDATION

JCP&L should modify its planning, substation design and operation criteria to provide additional feeders to substations with transformers larger than 10 MVA. This practice will reduce the number of customers affected by individual circuit problems and reduce overall customer outage time when extensive switching is needed to restore load. JCP&L should create a long-range plan (10-years) which will reduce the loading on each circuit by increasing the number of circuits for the system at least 50% over the next year.

5. Implement Additional Lightning Protection

Based on our review of outage reports for the last five years as discussed in Section 8, we believe there is a serious reporting problem as relates to outages due to lightning. Other electric utilities in the Northeast typically experience lightning related outages on the order of ten to a hundred times that of JCP&L. We suspect that many of the outages listed as an unknown cause along with other causes such as electrical failure were due to lightning.

The high-lightning-incidence states such as North Carolina and Florida have seen that grounding studies and enhancing system grounding have substantially mitigated lightning-related equipment damage. Additionally, the increased application of lightning arresters by utilities in Virginia, North Carolina and Florida (also Rhode Island), have all indicated a substantial improvement in system performance, including a significant enhancement to service reliability at a relatively low incremental increase in construction cost.

RECOMMENDATION

It is recommended that JCP&L implement a lightning protection and system grounding study. Our condition assessment found arrester application and pole line grounding deficiencies including failure to comply with construction installation specification (i.e., using guys to ground arresters is not good utility construction practice). An inspection program should be at least one of the study's recommendations. The following remediation actions can be used:

(a) Install additional lightning arresters.
(b) Reduce ground rod resistance to 25 ohms or less at arresters.
(c) Replace older arresters with MOV arresters.

Ground rod resistance can be reduced by increasing the total length of ground rods (i.e., use sectional ground rods), driving additional ground rods (distance between rods should be no less than maximum depth of any one rod), and use of special fillers such as Bentonite. Lowering ground rod resistance will not only reduce lightning-related outages but will also improve other problems such as stray voltage.

Substations also need attention and we recommend the following:

Since the effects of a direct lightning strike to an unshielded substation can be devastating, it is recommended that some form of direct strike protection be provided in future stations. Direct strike protection normally consists of shielding the substation equipment by using lightning masts, overhead shield wires, or a combination of these devices. The types and arrangements of protective schemes used are based on the size and configuration of the substation equipment.

For new substations, accepted industry standards require that all stations have a static or shield wire over at least the high side equipment and preferably over the entire station. A single shield wire provides a 30-degree cone of protection from direct lightning strikes to each side of the shield wire as measured from the vertical. This angle may be increased to 45 degrees for areas between shield wires when two or more are used. A single steel mast provides a cone of protection for an angle of 30 degrees from the mast. If more than one mast is used, the angle from the mast may be increased to 45 degrees for areas between the masts. Also, the shield wires or mast must be properly grounded. JCP&L should perform rolling ball lightning protection analysis on each substation and make the additions determined from the study.

Paragraph 7 of the MOU addresses this recommendation.

6. Substation Maintenance

Since the merger with FirstEnergy, management has instituted a standardized maintenance manual. In times prior to the merger, any given technician would have his own preferred practice of how to perform maintenance on a particular piece of equipment. This process has now been standardized so that maintenance is uniform each and every time.

JCP&L is concluding a program of testing each transformer on their system. In the process of their inspections, they found numerous transformer bushings going bad and proceeded to replace those bushings. We found evidence of this program to be true during the inspections by Booth & Associates, Inc. Many transformer bushings have been replaced. However, efforts toward completing this venture caused other scheduled maintenance to fall behind. Furthermore, the JCP&L/FirstEnergy standards allow overloading transformers as much as 25%. There are many old units currently being overloaded. This makes an aggressive transformer analysis program essential.

RECOMMENDATION

It is recommended that JCP&L, to the extent necessary, pursue hiring a larger staff of maintenance mechanics and/or bring in contract maintenance crews to allow regularly scheduled maintenance to proceed at the same time other critical remediation work is underway. It is critical, given the average age of the substation equipment, to maintain an aggressive maintenance program. In order to maintain good maintenance practices while upgrading and revamping their electric system, expanding substation staff or contractors may be necessary.

7. Work Order Process and Addition of Engineering, Inspection, and Construction Observation Staff

JCP&L has no effective work order, staking or inspection program. Based on the field interviews Booth found no structured process to have experienced engineers or technicians lay out the work to be accomplished or an inspection afterwards.

Booth determined throughout the interview process and the time spent with Jersey Central staff and the infrastructure condition assessment that there was little or no engineering design behind the distribution line construction process.

Additionally, there is virtually no independent inspection and construction observation process to assure compliance with the Jersey Central and FirstEnergy standards. In order to appropriately and fully incorporate all of the mid-level management, engineering and technician staff required, we strongly recommend that Mr. Steve Morgan conduct his own internal management audit with the primary focus being on the evaluation of the adequacy of mid-level management engineering and technician staff and utilization of the current staff. Even to the extent that such a management audit is not conducted, Booth has the following strong recommendation: Jersey Central needs to implement a process of distribution system design, construction observation and inspection which ensures that the power line facilities as constructed meet the Jersey Central and FirstEnergy standards and are designed and built in compliance with the National Electrical Safety Code. Furthermore, it is imperative that there is an independent construction observation and inspection program put in place.

Currently, Jersey Central allows its construction foremen responsible for the construction of the distribution system to perform the inspection on the lines which they and their supervised line crews construct. This process will not assure that lines are constructed in compliance with Jersey Central and FirstEnergy standards and the National Electrical Safety Code and good utility practice. It is imperative that after line construction or maintenance activity, separate construction observation is performed and discrepancy reports are produced and the party responsible for the inspection follows up that all discrepancies are rectified. The staff required for these roles should be engineers and technicians trained in power line construction and the National Electrical Safety Code and the Jersey Central and FirstEnergy construction standards. This independent group should be responsible for staking distribution lines, both overhead and underground, and other distribution line construction activity, design, construction observation and ultimate inspection of construction. Additionally, Jersey Central needs to have sufficient staff to perform regular and routine power line construction operation and maintenance surveys with a specific focus on bringing the overall system up to at least an average construction standard. This does not mean that 100% of the poor or below average system will be replaced. It does mean that there is a reasonable medium level between new system, above average system, average system, and poor system. The unsatisfactory system should always receive the number one priority for replacement. Booth's review of the system condition and interviews with management and construction personnel determined that inspection personnel are given entirely too much freedom in the layout of projects, design of projects, and ultimate construction observation and inspection of compliance with standards. Booth, in its condition assessment, identified an unsatisfactory percentage of system that was constructed, operated and maintained, that failed to comply with even the Jersey Central and FirstEnergy standards, together with failing to meet the National Electrical Safety Code in some cases and clearly not complying with customary utility design and construction practice. It is absolutely essential that Jersey Central has among its top priorities and action items to correct the deficiencies taking place in system design and construction process. This can only be done by changing the process and establishing a construction observation and inspection program which instills a clear enforcement of standards and builds a pride in the quality of system construction.

RECOMMENDATION

(a) Staking

All construction work orders should be processed by an experienced engineer or staking technician (staking engineer). The staking engineer should be knowledgeable of construction and design standards, NESC and other applicable codes, guying standards and schedules. The staking engineer should assess the work to be done, design the work, check all applicable standards and codes, then submit to construction or maintenance crews to process. JCP&L should develop a staking manual. TVPPA and other utilities can be an excellent source for examples.

(b) Inspection

Jersey Central and hopefully the entire FirstEnergy Company should implement a construction inspection program in which every month a minimum of 30% of the volume of construction will be inspected by a qualified engineer producing discrepancy reports and assuring that all discrepancies are rectified. However, on major projects, such as line extensions greater than 1,000 feet, 34.5 kV projects, new capacity installations, or any job deemed critical to a region, the distribution engineer frequently will visit the site to endure that the project is completed as designed and recommended. This represents approximately 40% of the Company's work according to Mr. Morgan. Furthermore, Mr. Morgan has stated that the remaining 60% of the construction is performed on an accelerated basis without engineering design or follow-up inspection. Preferably this engineer should have at least ten years experience in the design and construction of electric utility facilities and be capable to identify all levels of construction deficiencies and discrepancies both from the design and staking standpoint through the construction and as-build drawings standpoint. The engineer should also be completely trained in the NESC. Additionally, once every three years an additional independent quality control Operation and Maintenance Survey should be performed on all distribution system components from the substations down to the electric meter for a substantially representative no less than 30% of the system. It would be preferable for this program to be an ongoing process done on an annual rotating basis such that no less than 20% of the substations in a region have been incorporated into an O&M Survey process each year or that at least 50% of the system has been incorporated into an O&M process every three years as an additional level of quality control inspection.

8. Planning Studies and Standards

For Subtransmission Planning, JCP&L has implemented the following changes:

(a) The 50/50 forecast is used for single contingency line outage analysis. The 90/10 forecast previously used is included for informational purposes only.

(b) Beginning in the year 2001, the subtransmission conductor emergency ratings are based on a reduced ambient temperature of 30° C compared to a previously used standard of 35° C.

These changes in JCP&L planning criteria do not conform to good and customary utility practice. JCP&L's present practice of excessive circuit loadings require that auto-load transfer schemes be disabled during the summer peak periods at 80 substations in order to avoid overloading of system components during first contingency conditions. In reviewing Contingency Studies, it was noted that JCP&L performs almost no Distribution Contingency Studies.

RECOMMENDATION

With respect to subtransmission planning studies, we recommend:

- Returning to using a 90/10 load forecast for system normal analysis.
- Returning to using 35° C ambient temperature and 2 feet per second wind when rating conductors and other components. Also, JCP&L should return to industry standard of 75°C (167° F) conductor temperature for normal maximum ratings for local subtransmission conductors. For those newer lines designed to operate at 100°C, the 100°C (212°F) rating would be acceptable for <u>temporary</u> emergency situation.
- JCP&L should reconductor, add circuits and perform other improvements required to allow auto-load transfer schemes to function for first contingency subtransmission outages without overloading system components.
- JCP&L should prepare a 10-year local sub-transmission plan. This plan should include an interim 5-year step. A new 10-year local subtransmission plan should be prepared every 5 years. This way, there is always 5 years of future planning in existence. This plan should contain both a clear set of design criteria and reliability criteria. It should also reflect the regions' Facilities Connection Requirements and other FCRs as filed at FERC. It should also consider a plan for transferring portions of the distribution substation load from the 34.5 kV

system to higher voltage transmission lines for improved capacity and reliability.

Distribution planning studies should be prepared each year. These studies should be based on three or more years of projected growth. The projections should be the 90/10 projections rather than the 50/50 projections. Improvements dictated by the plan should be implemented prior to the summer peak each year rather than in response to the previous summer peak.

In conjunction with the recommended distribution planning studies, a distribution contingency study should be prepared for the entire distribution system. Although it may not be feasible to provide contingency backup service to all feeders, it should be the goal of JCP&L to provide backup from same substation feeders or from other substation feeders for most circuits. Along with providing feeder contingency, distribution substation transformers should be loaded such that other transformers in the same substation or in adjacent substations can serve the load if any single transformer fails. This should be achieved without imposing significant transformer loss of life.

9. Correct Loading Problems that Prevent Automatic Load Transfer Procedures from Operating as Designed

In each of the years 1999-2002 the total number of substations for which auto-load transfer schemes were disabled exceeded 80 substations. By disabling auto-load transfer schemes during the June-August peak period, the length of time customers would be subjected to an outage for a line section failure, an open breaker or other component failure in the subtransmission system would be increased from nearly instantaneous to likely hours. At best there would be time required, to perform a switching operation either manually or remotely or more likely to perform repairs after locating the outage, since the system has been overloaded at this point in the operation.

RECOMMENDATIONS

Auto-load transfer procedures need to be properly established so they do not have to be disabled during the summer peak periods. Our recommendations are:

- Dispatchers should be provided written procedures and trained on auto transfer scheme operation.
- A more reasonable level for circuit loadings should be adopted.
- Breaker phase relay settings should be reduced to match appropriate conductor loading.

- Contingency Studies for all distribution lines and substations should be performed.
- The number of circuits for the system should be increased by at least 50%.
- Ground trip relays must be installed on all transformers and circuit breakers.
- Three-phase reclosers should be retrofitted with ground trip relaying or sensing.
- A program of replacing large, single-phase reclosers with three-phase reclosers should be initiated. Single phase reclosers should be limited to 140 ampere maximum phase trip at which point three phase reclosers with ground trip should be applied.

10. Stray Voltage (Neutral to Earth Potential) Concerns

JCP&L customers in the area served by the Herbertsville Substation have complained of tingling sensations from stray voltage. There are many factors that contribute to stray voltage. Some factors which contribute to stray voltage cannot be controlled by the electric utility and neutral to earth voltage mitigation is extremely difficult. A zero potential difference from neutral to earth throughout an electric utility system cannot be achieved. Included are soil conditions, rock strata conditions, and extremely rural environments in which electric utility facilities have been expanded with predominantly single-phase facilities. There is also a large array of electric system conditions which contribute to stray voltage which can be controlled by the electric utility through implementation of mitigation efforts. The most notable of these activities are adequate or enhanced system grounding and phase balancing to keep the current on each of the conductors as close to equal as possible thus reducing the current flowing in the neutral. Our investigation indicates that Jersey Central's electric distribution power line grounding in some locations is poor and in other cases is inadequate. Electric utilities in the past benefited from the improved system grounding resulting from electric service bonding to home copper water pipe systems. New home construction has moved from 100 percent copper water piping which provided a source of good system grounding for the electric utility system to plastic pipe which provides no additional ground electrode source for the electric utility system. This means that both the houses and the electric utility system are not as well grounded today as they have been in the past.

It should be noted that all utilities are experiencing touch potential voltage at fiberglass swimming pools. This issue cannot be solved exclusively by the electric utility. The pool manufacturing industry must change its design and be a part of the solution if a real solution is to be achieved.

Underground electric distribution systems, up until the last ten years, were predominantly installed as direct-buried systems with bare concentric neutrals. This meant that the bare concentric neutrals served as an excellent grounding system as a counter poise. Because of the recognized problem associated with bare concentric neutral deterioration when in contact with earth, the industry moved to a jacket covering the bare concentric neutral. This eliminated the contact with the earth and the concentric neutral deterioration; however, it also eliminated the counter poise effect of the bare concentric neutral. Jersey Central will have to make a concerted effort on a prioritization basis to move towards improving and enhancing its grounding system in order to not only improve system performance, but to mitigate stray voltage conditions. This will take substantial time and capital investment.

RECOMMENDATIONS

The following recommendations relate to the stray voltage complaints in the vicinity of the Herbertsville Substation:

1. Completion of action items –1, 3 and 4 identified by Board Order dated 11/13/03, Docket No. E002120923. We find that JCP&L has produced evidence that action item 2 is unnecessary.

2. Monitoring and re-balancing efforts (action items 5-8) identified by Board Order dated 11/13/03, Docket No. E002120923.

3. Investigate use of soil enhancement materials, such as Bentonite clays, at distribution pole ground rods/electrodes to reduce soil resistivity during dry summer conditions.

4. Record distribution pole grounding resistance at the affected circuits. This measurement is easily accomplished with readily available clamp-on ground resistance testers, such as those made by AEMC or LEM. Additional grounding must be implemented until the grounding resistance is less than 25 ohms. UG dip poles should have a ground resistance of 10 ohms or less.

5. Patrol all feeders with stray voltage complaints to look for faulty equipment such as blown capacitor fuses in three phase banks, faulty arresters, broken insulators, loose or damaged ground wires, loose or damaged neutral connections. This should include measuring the resistance of neutral connections and splices.

6. Reduce circuit loading, if possible, to reduce the amount of neutral current flowing during peak loading if the circuits cannot be balanced. This can be accomplished by adding new circuits to reduce the overall load per circuit.

7. Consideration of installing isolation (block) devices if state/local codes permit to eliminate the problem at sensitive installations such as swimming pools until a utility system solution is found. Isolation devices are installed between the utility system neutral and the customer (secondary side) neutral per the 2002 National Electrical Safety Code 097D2. This recommendation should be used only after an exhaustive effort to correct the stray voltage problem.

8. Install adequate grounding and proper bonding throughout the system with particular emphasis at guys, arresters, reclosers and transformers.

11. Systemwide Sectionalizing Enhancement

JCP&L has taken a first step in enhancing system-wide sectionalizing by initiating a protective coordination study as part of the Accelerated Reliability Initiative. This is only a beginning and there is no plan in place to continue performing routine and periodic protective coordination studies. Electric utilities customarily maintain up-to-date protective coordination studies for the transmission, subtransmission and distribution systems. In order to improve reliability and properly apply breakers, relays, reclosers, fuses and switching equipment, a comprehensive, formal protective coordination study must be completed. Furthermore, new studies should be completed every five years while being reviewed annually and with every system upgrade program.

JCP&L performed a protective coordination study as part of the Accelerated Reliability Initiative. It was not a comprehensive protective coordination study with a fault current study and a fully exhaustive assessment of device additions, time current coordination curve development and extensive determination of sectionalizing equipment modifications and additions. The addition of 139 reclosers and 1,103 fuses on 1,108 circuits is only an initial start.

Booth identified significant system-wide sectionalizing enhancements that should be implemented even without a comprehensive protective coordination study.

To the extent that Paragraph 4 of the MOU addresses that recommendation, it should be considered to address this one as well.

RECOMMENDATIONS

JCP&L should immediately initiate a system-wide comprehensive protective coordination study tied to the capital budget which should be completed by October 2004. The study should include as a minimum:

(a) A complete fault current study on all subtransmission and distribution circuits calculating 3-phase, line to line, double line to line, phase to ground and minimum phase to ground (using 40 ohm and 30 ohm rule) fault currents on all circuits.

(b) Complete time current coordination curves for all circuit protective devices.

(c) Modify breaker relay settings and apply ground trip settings throughout the system following customary utility practices.

(d) Substantially expand the application of line reclosers and tap line fusing to comply with customary utility practices and designed to enhance reliability while meeting the coordination, design and reliability criteria standards to be developed.

(e) Expand the addition of sectionalizing equipment to detect, to the maximum extent possible, all faults including phase to ground minimum faults.

(f) Expand the addition of sectionalizing equipment to isolate faulted line sections to the most reasonable minimum component, outaging the smallest number of customers possible.

The results of the study should receive an independent outside expert review. Upon completion of the study, JCP&L should establish a phased approach to implementation. Booth recommends three phases:

(1) Sectionalizing equipment setting modifications and additions to be completed before the summer of 2005.

(2) Sectionalizing equipment modifications and additions to be completed over a three-year implementation program from June 2005 to June 2008.

(3) Sectionalizing equipment addition standards and protective coordination standards to be implemented with any system upgrade, improvement or line extension.

JCP&L should commit to a routine and periodic study cycle. Individual circuit analysis should be completed with the addition of any new substation or circuit. Regional or system-wide comprehensive studies should be completed every five years. Troubled circuits, those not meeting the reliability criteria, should be reviewed once a year at a minimum.

JCP&L believes that Paragraph 4 of the MOU addresses this recommendation.

Priority Three Action Items

Priority Three action items and recommendations will contribute to improved reliability in the long term. These recommendations predominantly affect the process and practices of JCP&L. Priority Three recommendations include:

1. Modify employee training approach.

2. Establish separate design standards for Central Region.

3. Automatic Meter Reading/Remote Power Monitoring.

4. NJBPU should perform a governance audit.

5. Management Audit Recommended for JCP&L

6. Adopt Phase II implementation.

1. Employee Training

The Regional presidents stated that JCP&L plans to rely on the Power Systems Institute Training Program as their only source of future line workers. JCP&L has an excellent facility in Phillipsburg that is not utilized effectively. JCP&L could provide lineman training at the Phillipsburg facility and not require an Associate Degree.

RECOMMENDATION

Modify approach to enhance participation. As an option, JCP&L should adopt a combined program using an apprentice training program and the PSI program. Provided incumbent employees meet the minimal requirements to be considered for other employment with JCP&L, these employees should not have to quit their jobs with JCP&L in order to receive the training required by JCP&L to be a line technician. We also recommend that JCP&L continue training journeyman linemen and technicians. JCP&L should include classroom instruction on the National Electrical Safety Code and proper construction practices. JCP&L must train its line technicians in how to construct lines per its published standards and the NESC.

2. Establish Separate Design Standards for Coastal Areas of the Central Region

Our review of FE Planning Standards provided on February 19, 2004 showed special design practices for coastal areas.

RECOMMENDATION

Differences in design standards and material standards have been adopted within the Central Region for facilities installed in coastal areas which operate in a harsher environment with salt contamination, higher winds and sandy soil. The following additional standard distribution practices should also be adopted and implemented:

- Construct with shorter spans to reduce conductor blowout during high winds.
- Stainless steel transformer tanks should be utilized.
- Stainless steel hardware should be installed throughout the area.
- Primary distribution facilities should be insulated to specifications one level higher than planned operating voltage.
- Inspections of facilities should be more frequent than non-coastal areas.
- Infrared test should be completed annually.
- Ground rods should be driven at least 20 feet.
- Pole line design should reflect the NESC coastal strength requirements for higher winds.
- A connector replacement program, particularly at transformers and services, should be instituted.

3. Automated Meter Reading/Remote Power Monitoring

Booth and Associates strongly recommends Jersey Central consider completing a comprehensive study of the implementation of automatic meter reading and the initial installation of remote power monitoring at the ends of troublesome circuits and at critical load centers including industrial customers. Other utilities have found that automatic meter reading is an economical choice for meter reading while it provides a secondary benefit of significantly improved power restoration through enhanced data. Although an automatic meter reading program requires a long-term implementation plan, it can be initially supplemented for reliability purposes by the application of remote power monitors. Remote power monitors using radio-controlled equipment or power line carrier or other communication means have been found by utilities to enhance system reliability through substantially improved data regarding power outages.

4. Governance Audit Recommended for JCP&L

FirstEnergy's regional management concept has been eliminated. Effective January 5, 2004, the Regional Presidents of Northern and Central Regions will report to a President of FE's Jersey Central Power & Light subsidiary. Other regional changes include naming a President of Ohio Edison who will be responsible for FE's former Eastern, Central, and Southern Ohio regions and

Pennsylvania Power in Western Pennsylvania and naming of a President of FE's Metropolitan Edison subsidiary. Prior to this change, FE's seven operating utilities were divided into nine operating regions, each with a Regional President. The entire GPU/FE merger process has been grounded in this regional management concept. It is unknown what changes will occur with adoption of the new subsidiary management concept.

The capital budgeting process is controlled by the FirstEnergy Board of Directors. The regional Presidents have very little autonomy to control the needed expenditures to upgrade the JCP&L infrastructure. There can be an inherent conflict in actions taken by FirstEnergy which impacts its operating utilities' ability to pay dividends to the parent company and decisions related to capital additions and maintenance expenditures needed to maintain and improve JCP&L's infrastructure.

Audit Division has expressed to us the opinion that JCP&L does not have in place written procedures to notify the Audit Committee of the BPU Audits and has not filed an 8K Report with the SEC to report the Focused Audit as a material event.

Furthermore, there are serious concerns we identified with the level of investment in the JCP&L infrastructure and operation and maintenance. This Focused Audit was not tasked with the role of governance evaluation. However, Booth identified sufficient concerns that we believe a governance audit is essential.

RECOMMENDATION

NJBPU should conduct a governance audit of JCP&L.

5. Management Audit Recommended for JCP&L

Booth believes, based on extensive interviews with senior management all the way down to field personnel and customers, that there is a significant divide between senior management and the distribution plant operating personnel. Booth believes there is insufficient middle management, including engineering staff and management and supervisory level staff. We have determined that many of the FirstEnergy and Jersey Central policies, practices and procedures are at or above customary utility practice levels. However, these policies, practices and procedures are not being implemented or followed by the maintenance, operation and construction personnel. The reason there is a substantial deviation between policy and implementation in such areas as construction, maintenance, inspection and planning is the failure on the part of Jersey Central to have a level of supervision and engineering expertise including inspectors and an inspection process that will assure that personnel are following policies and practices. The new president, Mr. Steve Morgan, should consider an internal informal management audit which specifically focuses on the deficiencies in management and engineering staff between the senior management level and the operations and maintenance and construction levels. Absent such a management audit and the incorporation of the appropriate levels of expertise and quantities of people in these intermediate management and engineering positions, we are confident that Jersey Central cannot effectively implement any of the programs and recommendations recommended in this study or as being attempted to be implemented through their own Accelerated Reliability Initiative and other initiatives.

RECOMMENDATIONS

It is recommended that the new president, Mr. Steve Morgan, initiate an informal management audit specifically designed for the purpose of evaluating the intermediate management and engineering staff requirements to assure the ability to bridge the gap which currently exists between the operation, maintenance and construction personnel and senior management.

6 Adopt Phase II Implementation

This report and the Focused Audit efforts have identified a large number of deficiencies in many areas of the JCP&L Planning, Operations and Maintenance Practices, Policies and Procedures. The Focused Audit has also identified communication and implementation problems and difficulty with standards between FirstEnergy and JCP&L. A preponderance of action items have been recommended as part of the Focused Audit. Due in part to the number of deficiencies identified and the time constraints on the production of the Focused Audit Report, it was virtually impossible to provide the extensive detail in each action item to develop the full procedures for implementation. The implementation procedures and processes as recommended in the action items require implementation by Jersey Central based on the recommendations and orders of the NJBPU. In order to assure appropriate implementation and the monitoring of JCP&L's progress, there will need to be the engagement of a specialist or group of specialists in each of the respective areas that can provide a periodic evaluation of the JCP&L progress. The NJBPU will need to have a monitor in place to assure proper implementation of its order on each of the recommended action items.

RECOMMENDATION

We recommend that NJBPU strongly consider a second phase to the Focused Audit. This second phase would entail the engagement of the appropriate outside expert, preferably a firm with multiple levels of expertise and personnel, to audit and monitor JCP&L's progress associated with the NJBPU's order that comes out of this Focused Audit. Such follow-up monitoring and auditing should take place on a periodic and systematic basis, with specific focus each six months on each of the action items and the scheduled implementation of whatever action items become part of the final order.